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PB-246 087

INSPECTION MANUAL FOR THE ENFORCEMENT OF NEW SOURCE PERFORMANCE STANDARDS: FOSSIL-FUEL-FIRED STEAM GENERATORS

PEDCo-ENVIRONMENTAL, INCORPORATED

PREPARED FOR
ENVIRONMENTAL PROTECTION AGENCY

JANUARY 1975

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EPA 340/1-75-002
FEBRUARY 1975

Stationary Source Enforcement Series

INSPECTION MANUAL FOR ENFORCEMENT OF NEW SOURCE PERFORMANCE STANDARDS

FOSSIL-FUEL-FIRED STEAM GENERATORS

PRICES SUBJECT TO CHANGE

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Office of Enforcement
Office of General Enforcement
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TECHNICAL REPORT DATA
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1. REPORT NO. EPA 340/1-75-002	2.	3. RECIPIENT'S ACCESSION NO. PB 246 087
4. TITLE AND SUBTITLE Inspection Manual for the Enforcement of New Source Performance Standards: Fossil-Fuel-Fired Steam Generators		5. REPORT DATE Issue: February 1975
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) T. W. Devitt and N. J. Kulujian		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS PEDCo-Environmental Specialists, Inc. Suite 13, Atkinson Square Cincinnati, Ohio 45246		10. PROGRAM ELEMENT NO.
		11. CONTRACT/GRANT NO. 68-02-1073
12. SPONSORING AGENCY NAME AND ADDRESS Environmental Protection Agency Office of Air and Water Programs Research Triangle Park, North Carolina 27711		13. TYPE OF REPORT AND PERIOD COVERED Final
		14. SPONSORING AGENCY CODE

15. SUPPLEMENTARY NOTES

One of a series of NSPS Enforcement Inspection Manuals

16. ABSTRACT

This document presents guidelines to enable enforcement personnel to determine whether new or modified fossil-fuel-fired steam generators comply with New Source Performance Standards (NSPS). Key parameters identified during the performance test are used as a comparative base during subsequent inspections to determine the facility's compliance status. The steam generating process, atmospheric emissions from these processes, and emission control methods are described. The inspection methods and types of records to be kept are discussed in detail.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Steam electric power plants Air pollution control Verification inspection Performance tests	New Source Performance Standards Enforcement Emission testing	13 B 14 D

18. DISTRIBUTION STATEMENT Release unlimited	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 131
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE 5.25

EPA Form 2220-1 (9-73)

U.S. GOVERNMENT PRINTING OFFICE: 1975—210-810:37

INSPECTION MANUAL FOR THE ENFORCEMENT OF NEW SOURCE PERFORMANCE STANDARDS:

FOSSIL-FUEL-FIRED STEAM GENERATORS

By

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Contract No. 68-02-1073

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Prepared for

U. S. ENVIRONMENTAL PROTECTION AGENCY
Division of Stationary Source Enforcement
Washington, D. C.

January 1975

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The Enforcement Technical Guideline series of reports is issued by the Office of Enforcement, Environmental Protection Agency, to assist the Regional Offices in activities related to enforcement of implementation plans, new source emission standards, and hazardous emission standards to be developed under the Clean Air Act. Copies of Enforcement Technical Guideline reports are available - as supplies permit - from Air Pollution Technical Information Center, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, or may be obtained, for a nominal cost, from the National Technical Information Service, 5285 Port Royal Road, Springfield, Virginia 22161.

ACKNOWLEDGMENT

This report was prepared under the direction of Mr. Timothy W. Devitt. Principal authors were Messrs. Norman J. Kulujian and Timothy W. Devitt.

Project Officer for the U.S. Environmental Protection Agency was Mr. John Butler. The authors appreciate the contributions made to this study by Mr. Butler and other members of the Division of Stationary Source Enforcement.

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1.0 INTRODUCTION

Pursuant to Section 111 of the Clean Air Act, the Administrator of the U.S. Environmental Protection Agency (EPA) promulgated particulate, sulfur dioxide, oxides of nitrogen, and opacity standards of performance for new and modified fossil-fuel-fired steam generators. These standards are applicable to each fossil-fuel-fired steam generating unit of more than 63 million Kcal (250 MM BTU) per hour heat input which is, or has been, constructed or modified after August 17, 1971.

Each state may develop a program for enforcing new source performance standards (NSPS) applicable to sources within its boundaries. If this program is adequate, EPA will delegate implementation and enforcement authority to the state for all affected sources with the exception of those owned by the U.S. Government. Coordination of activities between the state agency and the U.S. EPA, both Regional Office and Division of Stationary Source Enforcement, is thus essential for effective operation of the NSPS program. To facilitate such state participation EPA has established guidelines identifying the administrative procedures states should adopt to effectively implement and enforce the NSPS program.

The long-term success of the NSPS program depends largely upon the adoption of an effective plant inspection program. Primary functions of the inspection program are monitoring the NSPS performance tests and routine field surveillance. This manual provides guidelines for conducting such field inspections. However the same basic inspection procedures presented in this manual should also be of use in enforcing emission regulations contained in state air quality implementation plans. A summary of state emission regulations, presented in Section 2.1, is available for comparison to NSPS for steam generators.

2.0 SIP AND NSPS REQUIREMENTS

Standards of air pollution control performance for new and modified steam generators were originally proposed on August 7, 1971. The standards promulgated on December 23, 1971 altered the particulate sampling method, but the emission limits were adjusted to provide the same degree of particulate control as the originally proposed standards. New source performance standards are subject to Federal regulation code 40 CFR 60. The title 40 designates "Protection of Environment"; the number 60 classifies new sources.

An amendment on May 2, 1973, recognized that opacity levels during start-ups, shutdowns, and malfunctions are not representative conditions of performance tests unless otherwise specified. In addition, the amendment simplified reporting requirements. On June 14, 1974, sampling time requirements for particulate matter and gaseous pollutants were reduced, because performance test results did not show any decrease in the accuracy or precision using shorter sampling times.

On November 12, 1974, significant changes were proposed for new and modified sources. These amendments revised methods for reading opacities from continuous sources without time exceptions. EPA intends to propose opacity standards for steam generators, because current regulations allow time exceptions.

2.1 EXISTING SOURCES; STATE IMPLEMENTATION PLANS

Particulate emission standards promulgated by the states for power plants range from a low of 0.02 lb/MM BTU in Arizona, District of Columbia, Nevada and Vermont for plants larger than 10,000 MM BTU/hr to a high of 0.8 lb/MM BTU for small plants in Indiana, Iowa and North Dakota. The emission standards of most states for larger facilities range from 0.1 lb/MM BTU to 0.3 lb/MM BTU. Emission regulations for smaller plants are generally between 0.2 lb/MM BTU and 0.6 lb/MM BTU. Table 2.1 is a tabulation by state of the regulations limiting particulate emissions from power plants. The values, obtained from state regulations, are only illustrative and should not be used for enforcement

Table 2.1 POWER PLANT PARTICULATE EMISSION REGULATIONS BY STATE

State	Heat input, MM BTU/hr			
	0-199	200-1999	2000-9999	>10000
Alabama	0.27-0.18/0.35-0.21	0.13-0.13/0.14-0.12	0.12	0.12
Alaska	0.1	0.1	0.1	0.1
Arizona	0.41-0.35	0.24-0.20	0.21	0.09-0.02
Arkansas	None	None	None	None
California	Each county has its own regulation			
Colorado	0.27-0.15	0.15-0.1	0.1	0.1
Connecticut	0.10/0.20	0.10/0.20	0.10/0.20	0.10/0.20
Delaware	0.3	0.3	0.3	0.3
Dist. of Columbia	0.10-0.07	0.07	0.04	0.02
Florida	None	None-0.1	0.1	0.1
Georgia	Formula			
Hawaii	0.6	0.6	0.6	0.6
Idaho	0.6-None	None	None	0.12
Illinois	0.1	0.1	0.1	0.1
Indiana	0.6/0.8	0.6/0.8	0.6/0.8	0.6/0.8
Iowa	0.6/0.8	0.6/0.8	0.6/0.8	0.6/0.8
Kansas	0.41-0.35	0.24-0.21	0.21-0.13	0.12
Kentucky	0.38-0.32	0.26-0.22	0.19-0.13	0.11
Louisiana	0.6	0.6	0.6	0.6
Maine	0.6-0.3	0.3	0.3	0.3
Maryland	0.08/0.6-0.35	0.05/0.35	0.05/0.20	0.05/0.12
Massachusetts	0.10/0.15	0.10-0.05/0.15	0.05/0.15	0.05/0.15
Michigan	Regulations given in lbs/1000 lbs gas			
Minnesota	0.4/0.6	0.4/0.6	0.4/0.6	0.4/0.6
Mississippi	0.6-0.41	0.41-0.26	0.26	0.19
Missouri	0.41-0.35	0.6-0.24	0.6-0.13	0.6-0.12
Montana	0.6-0.35/0.6-0.4	0.2/0.40	0.2/0.28	0.12/0.19
Nebraska	0.6-0.35	0.35	0.21	0.12
Nevada	0.6-0.35	0.35	0.21	0.09-0.02
New Hampshire	0.40-0.23/0.46-0.40	0.23/0.40-0.31	0.20-0.12/0.28-0.2	0.12/0.19
New Jersey	0.22-0.15	0.1	0.1	0.1
New Mexico	0.38-0.33	0.33	0.19-0.14	0.135
New York	0.44-0.37	0.37-0.1/0.37-0.34	0.1/0.23-0.16	0.1/0.14
North Carolina	0.6-0.33	0.33	0.18	0.10
North Dakota	0.49-0.44/0.8	0.44/0.8	0.33-0.25/0.8	0.24-0.18/0.8
Ohio	0.04-0.2	0.2	0.15-0.1	0.15-0.1
Oklahoma	0.6-0.35	0.35	0.2	0.1
Oregon	0.17/0.33	0.17/0.33	0.17/0.33	0.17/0.33
Pennsylvania	0.4-Formula	Formula-0.1	0.1	0.1
Rhode Island	Same as process weight regulations			
South Carolina	0.6	0.6-Dependent on stack height		
South Dakota	0.3	0.3	0.3	0.3
Tennessee	0.4-0.16/0.34	0.16-0.1/0.34	0.1/0.18	0.1
Texas	0.3	0.3	0.3	0.3
Utah	85% Control			
Vermont	0.3	0.3-0.1	0.02	0.02
Virginia		Formula		0.10
Washington	0.33	0.33	0.33	0.33
West Virginia	0.05	0.05	0.05	0.05
Wisconsin	0.15	0.15-0.10	0.10	0.10
Wyoming	0.1/0.6-0.4	0.1/0.4	0.1/0.27	0.1/0.18

Where a range is given, the limit depends on the location and installation date
Where new and existing regulations differ, the regulations are expressed as:
new source limit/existing source limit

purposes since in many cases the states' regulations contain a variety of qualifications and exceptions.

Forty-four states limit visible emissions from new plants to below 20 percent opacity. Regulations range from "no visible discharge" in Maryland and the District of Columbia to 60 percent opacity for existing installations in Minnesota and for short periods of time in Pennsylvania and Vermont. Table 2.2 is a tabulation of opacity limitations for the various states; the same limitations apply to this listing as apply to Table 2.1.

SO_2 control regulations limit either the sulfur content expressed in weight percent or lb S/MM BTU, or the SO_2 emissions expressed in lb SO_2/MM BTU. Weight percent limitations range from 0.2 percent for oil in Idaho to 3 percent for coal and oil in Georgia with the majority being under 1.5 percent. Only three states limit sulfur content in lb S/MM BTU; the range is 0.28 percent to 2 percent. SO_2 emission limitations are the most prevalent, ranging from a high of 6 lb SO_2/MM BTU in rural Indiana to a low of 0.3 lb SO_2/MM BTU in New Jersey. The 0.3 lb SO_2/MM BTU in New Jersey is applied in conjunction with fuel sulfur content limitations. The general range of SO_2 emission limits is from 1.0 to 3.0 lb SO_2/MM BTU. Table 2.3 is a tabulation of SO_2 control limits by state; the same limitations apply to this listing as apply to Table 2.1.

Twenty-eight states limit NO_x emissions from power plants. The majority of the states limit gaseous fuels to 0.2 lb NO_x/MM BTU and liquid fuels to 0.3 lb NO_x/MM BTU. Solid fuel limitations range from 0.3 lb NO_x/MM BTU in Massachusetts and Delaware to 1.3 lb NO_x/MM BTU in North Carolina. Table 2.4 lists the NO_x emission limitations by state; the same limitations apply to this table as apply to Table 2.1.

2.2 SUMMARY OF NSPS

The standards for new or modified steam generators are summarized below. A complete copy of the regulations, plus revisions through November, 1974, is presented in Appendix A.

2.2.1 Emission Standards

Allowable limits for opacity, particulate matter, sulfur dioxide, and oxides of nitrogen are presented in Table 2.5.

Table 2.2 POWER PLANT VISIBLE EMISSION RGULATIONS BY STATE

State	% Opacity[a]	State	% Opacity[a]
Alabama	20	Montana	20-40
Alaska	20	Nebraska	20
Arizona	40	Nevada	20
Arkansas	20-40	New Hampshire	20-40
California	diff. for each county	New Jersey	20
Colorado	20	New Mexico	20
Connecticut	20	New York	20-40
Delaware	20	North Carolina	20-40
Dist. of Columbia	No visible discharges	North Dakota	20-40
Florida	20	Ohio	20
Georgia	20-40	Oklahoma	20
Hawaii	20-40	Oregon	20-40
Idaho	20-40	Pennsylvania	20-60
Illinois	20-30	Rhode Island	20
Indiana	40	South Carolina	20-40
Iowa	20	South Dakota	20
Kansas	20-40	Tennessee	20-40
Kentucky	20	Texas	20-30
Louisiana	20	Utah	20-40
Maine	40	Vermont	40-60
Maryland	No visible discharges	Virginia	20
Massachusetts	20	Washington	20-40
Michigan	40	West Virginia	10-20
Minnesota	20-60	Wisconsin	20
Mississippi	40	Wyoming	20-40
Missouri	20-40		

[a] Does not include opacity of uncombined water. Where a range is given, the limits depend upon location, effective date and whether it is a new or existing source.

Table 2.3 POWER PLANT SO_2 EMISSION LIMITATIONS BY STATE

	Fuel limitations[a]				Emission limitations[a]	
	%S		lbs S 10^6 BTU		lbs SO_2/10^6 BTU	
State	Oil	Coal	Oil	Coal	Oil	Coal
Alabama					1.2-1.5	1.2-1.5
Alaska					1.0	1.0
Arizona					b	b
Arkansas					b	b
California					c	c
Colorado					0.3-1.0	0.3-1.0
Connecticut	0.5	0.5			0.55	0.55
Delaware	0.3	0.3				
Dist. of Columbia	0.5-.8	0.5-1.0				
Florida					0.8-1.1	1.2-1.5
Georgia	2.5-3.0	2.5-3.0			0.8[d]	1.2[d]
Hawaii	0.5-2.0	0.5-2.0				
Idaho	0.2-0.3	0.7				
Illinois	1.0	1.0			0.3-1.0	1.2-1.8
Indiana					1.2-6.0[e]	1.2-6.0[e]
Iowa					1.5	5.0
Kansas					3.0	3.0
Kentucky					0.8-2.5	1.2-4.0
Louisiana					f	f
Maine	1.5-2.5	1.5-2.5				
Maryland	0.3-0.5	1.0				
Massachusetts			1.7-0.55	0.28-0.55		
Michigan	0.3-2.0	0.3-2.0			1.7-2.2	2.4-3.2
Minnesota	1.5	1.5				
Mississippi					2.4-4.8	2.4-4.8
Missouri	f	f			0.5-2.3	0.5-2.3
Nebraska					g	g
Nevada	1.0				1.4	1.4
New Hampshire	0.4-1.0					
New Jersey	0.2-1.0	0.2-1.0			3.0	3.0
New Mexico					0.34	0.34
New York	0.2-0.3	0.3	0.6-1.65	1.4-2.0		
North Carolina		1.0			1.6-2.3	1.6-2.3
North Dakota					3.0	3.0
Ohio					1.0-3.1	1.0-3.1
Okalhoma					0.3-0.8	2.0
Oregon	0.3-2.5[d]	1.0[d]			0.8-1.4[d]	1.2-1.6[d]
Pennsylvania	0.2-0.3	0.3			0.6-3.0	0.6-3.0
Rhode Island	1.0	1.0				
South Carolina					1.6-2.3	2.0-2.3
South Dakota					3.0	3.0
Tennessee	2.0	2.0				
Texas					b	3.0
Utah	1.5	1.0				
Vermont	1.0-1.5	1.0-1.5				
Virginia					h	h
Washington	0.3					1.5[e]
West Virginia	1.5	2.0			1.6-3.2	1.6-3.2
Wisconsin					0.8[d]	1.2[d]
Wyoming					None	None

a) Where a range is given limit depends on location, date, whether a new or existing source, etc.

b) Emissions may not cause ground level concentrations to exceed specified limit.

c) Regulated by county.

d) For new sources only.

e) Some counties have no regulations.

f) 2000 ppm.

g) Cannot exceed 1971 emissions.

h) Determined by formula.

Table 2.4 POWER PLANT NO_X EMISSION LIMITATIONS

State	Type of fuel			State	Type of fuel		
	Gas	Liquid	Solid		Gas	Liquid	Solid
Alabama[a]	0.2	0.3	0.7	Montana			
Alaska				Nebraska	0.2	0.3	
Arizona				Nevada			
Arkansas				New Hampshire			
California	Regulated by County			New Jersey			
Colorado				New Mexico	0.2-0.3	0.3	0.45-0.7
Connecticut	0.2	0.3	0.7	New York	0.2	0.3	0.7
Delaware	0.2	0.3	0.3	North Carolina	0.6	0.6	1.3
Dist. of Columbia	0.2	0.3	0.7	North Dakota			
Florida[a]	0.2	0.3	0.7	Ohio	0.2	0.3	0.9
Georgia[a]	0.2	0.3	0.7	Oklahoma	0.2	0.3	0.7
Hawaii				Oregon			
Idaho				Pennsylvania	0.3	0.3	
Illinois[a]	0.3	0.3	0.7-0.9	Rhode Island	0.3	0.3	
Indiana[a]	0.2	0.3	0.7	South Carolina			
Iowa	0.2	0.3		South Dakota	0.2	0.3	
Kansas	0.3	0.3		Tennessee			
Kentucky	0.2	0.3	0.7-0.9	Texas			
Louisiana				Utah			
Maine				Vermont	0.3	0.3	
Maryland	0.2	0.3	0.5	Virginia	0.2	0.3	0.7
Massachusetts[a]	0.3	0.3	0.3	Washington			
Michigan				West Virginia			
Minnesota	0.2-0.3	0.3-0.4		Wisconsin[a]	0.2	0.3	0.7
Mississippi				Wyoming	0.2	0.3	
Missouri							

[a] New sources only

Table 2.5 SUMMARY OF EMISSION STANDARDS FOR NEW AND MODIFIED STEAM GENERATORS

Item	Standard	Fuel
Opacity	20%	All
Particulate	0.18 gm/MM cal input (0.10 lb/MM BTU input)	All
SO_2	1.4 gm/MM cal input (0.8 lb/MM BTU input)	Oil
SO_2	2.2 gm/MM cal input (1.2 lb/MM BTU input)	Coal
SO_2		Combination
NO_x	0.36 gr/MM cal input[a] (0.20 lb/MM BTU input)	Gas
NO_x	0.54 gr/MM cal input[a] (0.30 lb/MM BTU input	Oil
NO_x	1.26 gr/MM cal input[a] (0.70 lb/MM BTU input)	Coal[b]
NO_x	Prorated	Combination

a) Expressed as NO_2.
b) Except lignite.

2.2.2 Performance Testing

Testing of new or modified sources must be performed no later than 60 days after achieving maximum production rate, but no longer than 180 days after initial start-up. The tests must be conducted at representative performance using fuels representative of those used during normal operation.

The owner or operator has the following responsibilities:

- To give a minimum of 30 days notification of scheduled tests.
- To give a minimum of 30 days notice of anticipated start-up. EPA must be notified of the actual start-up date within 15 days after such date.
- To provide adequate sampling ports, safe sampling platforms, safe access to the sampling sites, and utilities for sampling and testing equipment.
- To perform emission tests and furnish a written report of test results to the Administrator.

The various testing methods and specified conditions are listed in Table 2.6 for each pollutant. Descriptions of the testing procedures are specified in 40 CFR 60. Each test consists of three repetitions of the applicable test method. Results of the repetitive tests are averaged to determine compliance. EPA personnel may perform additional tests at any reasonable time at any representative load condition.

The opacity revisions, promulgated on November 12, 1974, clarify procedures for determining opacity of plumes containing water vapor, define observational portions, and delete the requirement for calculating average opacity.

2.2.3 Stack and Process Monitoring

Instrumentation required for monitoring stack emissions and process variables are listed below.

- Smoke detector to continuously monitor coal- and oil-fired steam generators.
- SO_2 detector to continuously monitor coal- and oil-fired units. If low-sulfur fuel is used, only a daily analysis record is required.
- NO_x detector to continuously monitor all fuel systems. As of September 11, 1974, generators fired with lignite are exempt from nitrogen oxides standards.

Table 2.6 SUMMARY OF TEST METHODS FOR NEW AND MODIFIED STEAM GENERATORS

Pollutant	Sampling method	Total samples required		Minimum running time/ sample, min.	Minimum sampling volume dry dscf (dscm)	Comments
		Per repetition	Per test			
Particulate	1, 5	1	3	60	30 (0.85)	a) Gas analysis determined by Method 3. b) Moisture determined by Method 5.
SO_2	6	2	6	20	--	a) Samples taken at 30-minute intervals. b) Sampling point at centroid of duct if area less than 50 ft^2. c) Sampling point no closer than 3 feet from wall if duct area greater than 50 ft^2.
NO_x	7	4	12	0.25	--	a) Sampling point coincident with point used or calculated for sampling SO_2.

- Fuel consumption instrumentation to continuously monitor the quantity (tons, gallons, or cubic feet) of fuel consumed by coal-, oil-, or gas-fired units.

- Electrical output system to record daily average electrical output and minimum and maximum hourly generation rate.

Instrument accuracy must be within ± 20 percent, with a confidence level of 95 percent, and calibrated at least once every 24 hours unless the instrument manufacturer specifies more frequent calibration.

The September 11, 1974 proposed rules are significant changes in monitoring requirements. These include the addition of an oxygen monitor, techniques for adjusting and calibrating extractive and non-extractive monitoring devices, and monitoring alternatives if gas stream interferences inhibit the use of conventional instruments.

2.2.4 Recordkeeping and Reporting

All records are to be kept by the facility for two years following the date of measurement and summary. The plant must be prepared to make available to EPA any records necessary to determine performance. Emission data shall be made available to the public.

Table 2.7 summarizes the items to be recorded, and frequency of data to be recorded.

The promulgation of the September 11, 1974 additions will revise the recordkeeping and reporting requirements. Data reduction will be performed monthly rather than daily, allowing the use of computerized data reduction techniques. For coal- and oil-fired units, fuel analysis may be substituted for the previously mandatory SO_2 monitors. Conditions for reporting excess emissions are defined for opacity, SO_2 and NO_x.

Table 2.7 RECORDKEEPING REQUIREMENTS FOR STEAM GENERATING FACILITIES

Item	Applicable to fuel type	Recordkeeping frequency	Comments
Smoke	Coal, oil	Continuous	Convert to opacity.
SO_2	Coal, oil	Continuous	Convert to lb/MM BTU; required for use of low-sulfur fuel.
NO_x	All	Continuous	Convert to lb/MM BTU.
Fuel Analysis			
Sulfur	Coal, oil	Weekly, Daily[a]	
Heating value	All	Weekly	
Ash content	Coal, oil	Weekly	
Fuel rate	All	Daily	
Average electrical output	All	Daily	
Minimum and maximum hourly generation	All	Daily	
Compliance tests	All	As required	
Instrumentation calibration	All	As required	
Malfunctions, start-up, shutdowns, etc.	All	As required[b]	

[a] Daily records are required when facility attempts to meet the SO_2 regulation by burning low-sulfur fuel.

[b] Revised Federal Register, Vol. 38, No. 84, May 2, 1973. Quarterly reports are required including malfunction, corrective actions and preventive means.

3.0 PROCESS DESCRIPTION, ATMOSPHERIC EMISSIONS, AND EMISSION CONTROL METHODS

A brief description of the steam generating operation is presented below to familiarize the inspector with the basic theory. Atmospheric emissions and their control are also discussed.

3.1 PROCESS DESCRIPTION

Emission performance standards apply to steam generating units with heat inputs of 63 MM Kcal (250 MM BTU) per hour, which are generally electrical power plant generators or large industrial units producing steam and/or electricity. Although coal-, oil-, and gas-fired boilers differ in design and operation, the basic processes are similar. In every case the chemical energy in the fuel is converted into heat, mechanical energy, or electrical energy.

A simplified diagram of a large indirect-fired heat exchange system is shown in Figure 3.1. The major components of the combustion process are the fuel-burning equipment, the steam-producing system, and the control or instrumentation system. Figure 3.2 illustrates the layout of a coal-fired boiler.

Fuel is introduced into the boiler furnace in one of two ways; it is either fed by one of many grate systems, or it is injected through a burner. In either case, the fuel burns to form combustion gas products, which then flow through or over the various heat transfer surfaces in the steam generator. The feedwater is heated in the economizer and heat exchanger areas to generate steam. The air leaving the economizer and entering the air heater section contains enough heat to raise the inlet temperature of the air going to the firebox. This improves boiler efficiency and helps dry the fuel (if solid fuel is used).

The water and steam are processed through a recirculatory system that includes a drum, downcomer tubes, and riser tubes. The drum is located at a high elevation in relation to the heat exchanger structure. It receives

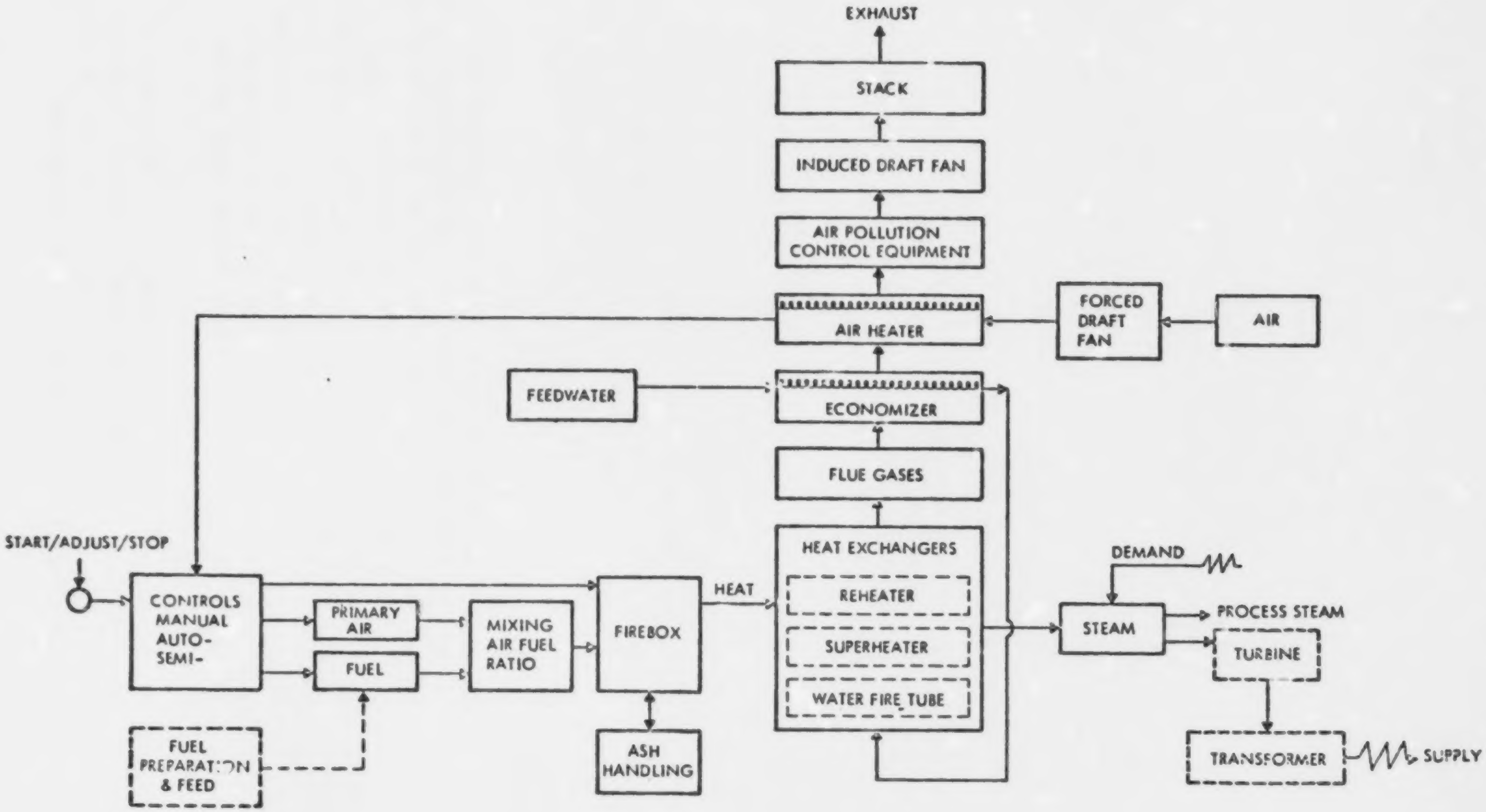
EXHAUST
STACK
INDUCED DRAFT FAN
AIR POLLUTION CONTROL EQUIPMENT
AIR HEATER
FORCED DRAFT FAN
AIR
FEEDWATER
ECONOMIZER
FLUE GASES
START/ADJUST/STOP
CONTROLS MANUAL AUTO- SEMI-
PRIMARY AIR
FUEL
MIXING AIR FUEL RATIO
FIREBOX
HEAT
HEAT EXCHANGERS
REHEATER
SUPERHEATER
WATER FIRE TUBE
DEMAND
STEAM
PROCESS STEAM
TURBINE
TRANSFORMER
SUPPLY
FUEL PREPARATION & FEED
ASH HANDLING

Figure 3.1 Simplified diagram of a large indirect-fired heat exchange system.

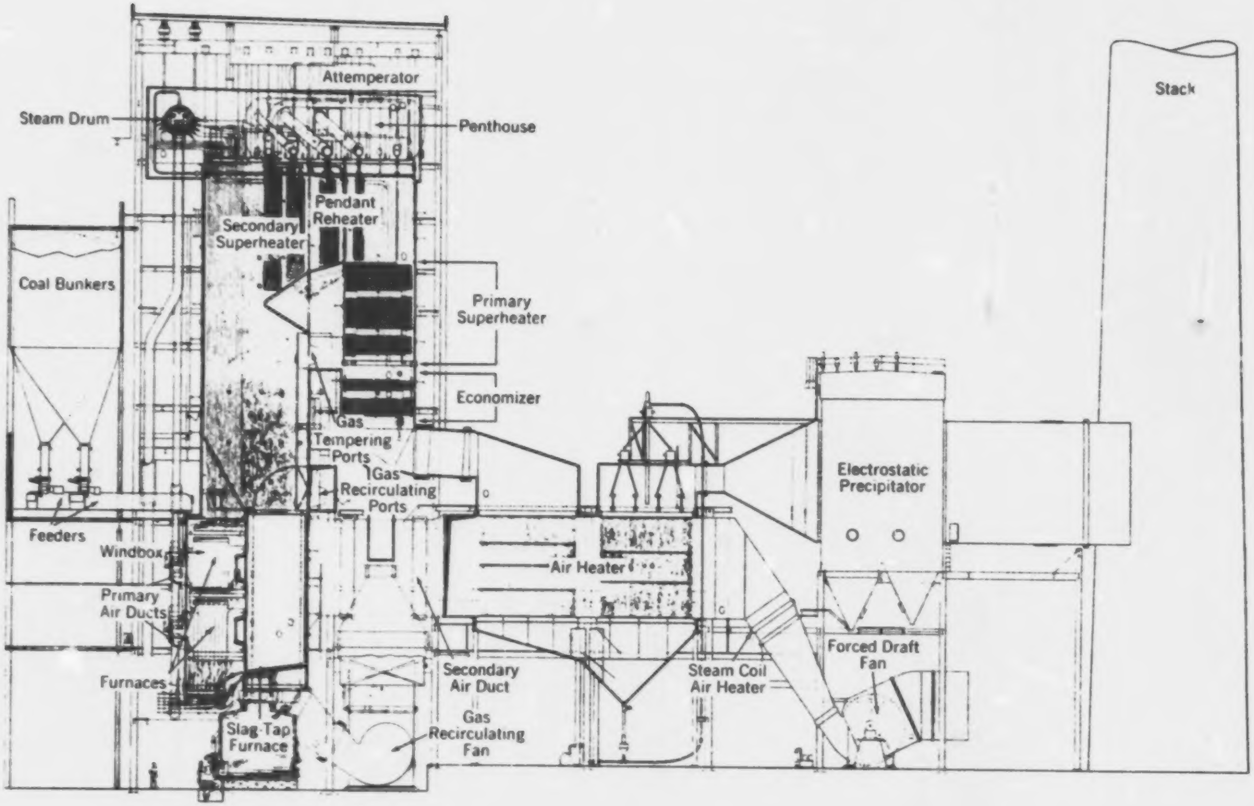
Attemperator
Steam Drum
Penthouse
Pendant Reheater
Secondary Superheater
Coal Bunkers
Primary Superheater
Economizer
Gas Tempering Ports
Gas Recirculating Ports
Feeders
Windbox
Primary Air Ducts
Furnaces
Slag-Tap Furnace
Air Heater
Secondary Air Duct
Gas Recirculating Fan
Steam Coil Air Heater
Electrostatic Precipitator
Forced Draft Fan
Stack

Figure 3.2 Diagram of coal-fired boiler.

(Courtesy of Babcock and Wilcox Company, New York, New York) heated feedwater that flows to the base of the steam generator in the downcomer tubes, which in turn feed riser tubes forming the inside walls of the generator. Feedwater is converted to steam in the risers and returns to the upper portion of the drum; the steam is then used in a process or fed to high-pressure turbines to generate electricity.

After the exhaust gases leave the air heater, they are ducted through an air pollution control system to the exhaust stack. The various emission control methods are discussed in detail in Section 3.3.

More complete process descriptions of steam generators are given in textbooks provided by equipment manufacturers.[1,2] Details of combustion chemistry and fuel characteristics are also available.[3,4]

3.2 ATMOSPHERIC EMISSIONS

The points of emission from coal-, oil-, or gas-fired steam generators are illustrated in Figure 3.3. NSPS limits are applicable only to emissions that result from the combustion process and exit through the stack. Furthermore, processes using fuels other than the conventional variety (i.e., coal, oil, or gas) are not subject to the NSPS for steam generators. These include the burning of waste gases, refuse, or any other materials capable of producing heat by exothermic reaction.

Particulate emission rates vary with the type of fuel, as well as with boiler design and operating factors. Opacity and particulate matter are increased as the fuel ash content increases. Correct air-to-fuel ratios help minimize particulate emissions. Either an excess or lack of air restricts organic matter from being oxidized in the boiler. Oil-fired units require proper oil preheat temperatures and coal-fired steam generators must burn the proper size coal to minimize emissions. Facilities using natural gas have no problems with plume opacity or particulate emission rate unless the unit is operated poorly. Factors that affect particulate emissions are discussed in more detail in References 5 and 6.

The amount of sulfur dioxide formed in the combustion process is dependent on the sulfur content of the fuel. Essentially all sulfur in the fuel is oxidized to SO_2 and one to five percent of the SO_2 is oxidized to SO_3 during combustion. About 95 percent sulfur is emitted to the atmosphere, the remainder reacting with the ash. Sulfur emissions from combustion sources are discussed in detail in Reference 7.

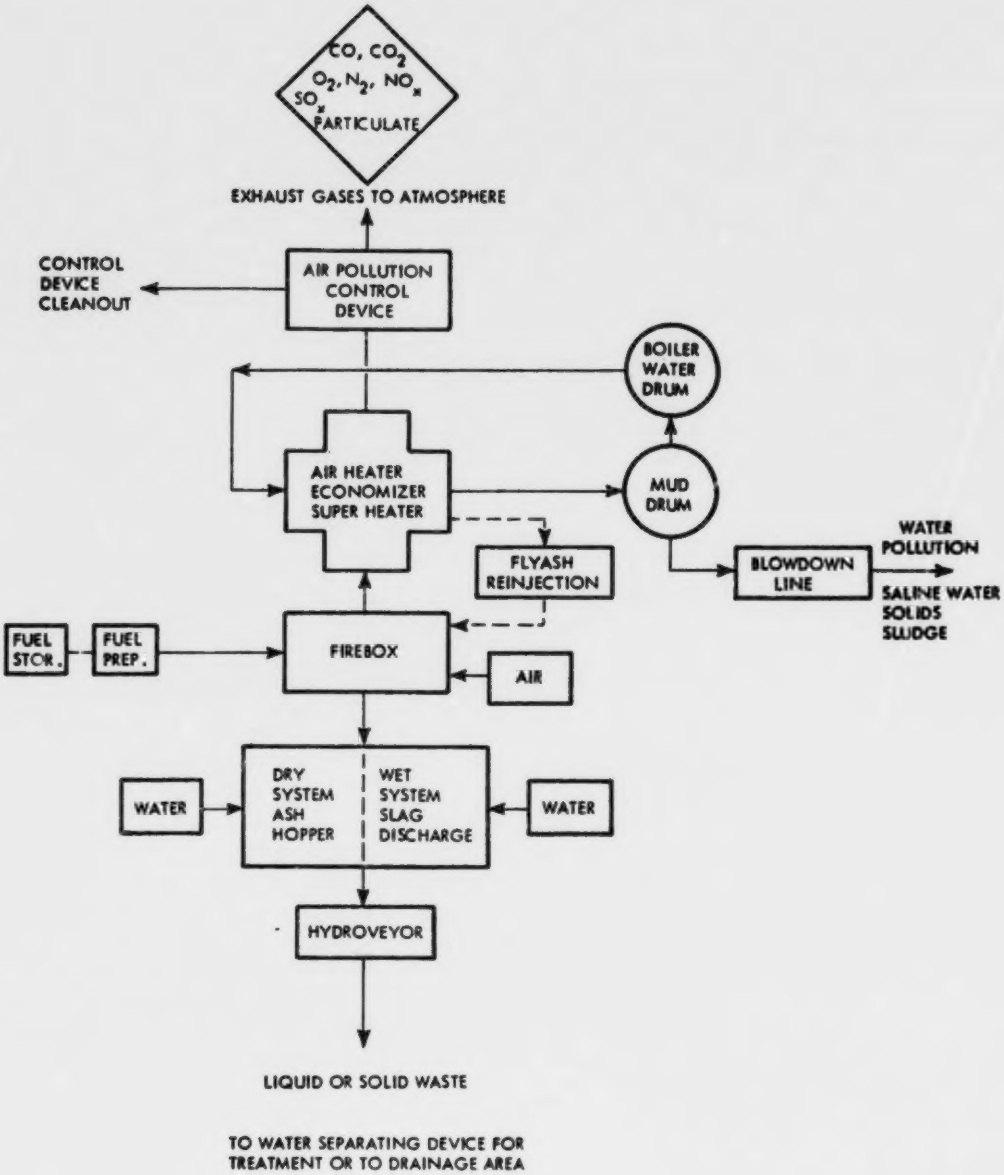
CO, CO2
O2, N2, NOx
SOx
PARTICULATE
EXHAUST GASES TO ATMOSPHERE
CONTROL DEVICE CLEANOUT
AIR POLLUTION CONTROL DEVICE
BOILER WATER DRUM
AIR HEATER ECONOMIZER SUPER HEATER
MUD DRUM
FLYASH REINJECTION
BLOWDOWN LINE
WATER POLLUTION
SALINE WATER
SOLIDS
SLUDGE
FUEL STOR.
FUEL PREP.
FIREBOX
AIR
WATER
DRY SYSTEM ASH HOPPER
WET SYSTEM SLAG DISCHARGE
WATER
HYDROVEYOR
LIQUID OR SOLID WASTE
TO WATER SEPARATING DEVICE FOR TREATMENT OR TO DRAINAGE AREA

Figure 3.3 Emission source from a steam generating facility.

NO_x emissions from a steam generator are highly dependent upon the combustion characteristics of the particular unit. Nitric oxide (NO) is formed in the furnace at temperatures above 2800°F. The main factors affecting the amount of NO_x formed are the flame and furnace temperature, the percentage of fuel-bound nitrogen, the length of time the combustion gases are maintained at the flame temperature, the rate of gas cooling, and the amount of excess air present in the flame. Reference 8 is a report of a field study of NO_x boiler emissions.

3.3 EMISSION CONTROL METHODS

Methods of controlling atmospheric emissions include installation of control devices, fuel substitution, and boiler modification in the case of nitrogen oxide emissions.

3.3.1 Particulate Emission Control Methods

Natural gas and low-ash fuel oils (less than 0.5%) can be used to meet the particulate emission standard. However, such premium fuels are in short supply and will probably not be available for use in new steam-electric generating units.

Electrostatic precipitators are the most commonly used particulate emission control device. In recent years, various types of wet scrubbers have also been used, particularly in conjunction with flue gas desulfurization (FGD) systems. Scrubbers offer some advantages over precipitators in that they are relatively insensitive to variations in fuel composition and boiler operating characteristics. Fabric filters have been used to only a very limited extent although their use may increase in the future because of their ability to control fine particulate emissions. Fabric filters are not discussed further in this report. The NSPS inspector is expected to have a working knowledge of the theory and capabilities of the commonly used control devices; such information is readily available in several references.[9,10,11,12]

Electrostatic precipitator collection efficiency, and hence design, is affected by the coal sulfur content, ash composition, and flue gas temperature, all of which influence fly ash resistivity. Fly ash resistivity increases, and precipitator efficiency decreases, as the fuel sulfur content decreases. One method of overcoming the high fly ash resistivity is the use of a "hot" precipitator which operates at temperatures in excess of 550°F where resistivity is relatively low and independent of fuel sulfur content. Because of the higher temperatures, the hot precipitator handles a much larger flue gas volume than a "cold" precipitator on an equivalent sized boiler. Thus most "hot" precipitators are being installed on new units, where there are no space restrictions, or on relatively new plants which also have adequate space. Sulfur trioxide, SO_3, injected into the gas stream will also lower particle resistivity.

The amount of power input to the precipitator is related to its operating efficiency. High resistivity fly ash can limit the amount of useful power that the power supply (transformer-rectifier sets) can deliver to the precipitator, even though the power supply is adequately sized. Thus checking the delivered power to the unit (by reading the secondary current and voltage inputs to each precipitator section) is an easy check as to whether the precipitator is performing adequately.

Many precipitators are designed to meet required collection efficiencies with one or more electrical sections out of service. Thus sections can be de-energized because of a short or other electrical failure without requiring the boiler to come off-line for precipitator repairs.

Wet scrubbing systems are being used for particulate collection by several utilities, often in conjunction with FGD systems. Efficient particulate removal usually requires that some type of venturi scrubber be used, with pressure drops on the order of 10 to 15 inches of water. Important operating parameters influencing particulate collection efficiency are the pressure drop and liquid-to-gas (L/G) ratio, usually about 10 to 20 gallons/1000 acf of flue gas for a venturi scrubber. Higher liquid volumes, up to 50 gallons per 1000 acf, are used to avoid scaling in the hardware.

3.3.2 Sulfur Dioxide Control Methods

SO_2 emissions can be reduced by using low-sulfur fuel or FGD systems. Many utilities have decided to use low-sulfur coal although as mentioned earlier this can reduce the particulate collection efficiency of electrostatic precipitators by increasing fly ash resistivity. Furthermore, since utilities normally receive coal from several different sources, it is necessary to install rather elaborate coal-blending facilities to ensure that SO_2 emissions on a two-hour average (or other short-term basis) do not exceed applicable standards. The adequacy of the blending system to store and then properly mix the various sulfur content coals must be established by reviewing the system design.

There are several types of FGD systems either currently in use or under development. The most widely used are lime/imestone, magnesium oxide, and sodium solution scrubbing. These processes are briefly described below. Additional information is available from various FGD system manufacturers.

Lime/Limestone Scrubbing

In this process lime or limestone is used to make an alkaline slurry which is circulated through an absorber where it reacts with the sulfur oxides in the flue gas. Various calcium sulfite and sulfate salts are formed by the reaction which are then removed in settlers or clarifiers. The sludge produced by the system can be chemically stabilized to produce a suitable landfill material or stored in sludge ponds which have adequate barriers to prevent surface and groundwater contamination.

Limestone-based systems operate with SO_2 removal efficiencies of approximately 85 to 90 percent. Use of lime, which is more reactive than limestone, enables the system to operate with efficiencies in excess of 90 percent.

Magnesium Oxide Scrubbing

The magnesium oxide scrubbing process is a regenerable process producing sulfuric acid as a by-product. A slurry of magnesium oxide is circulated through an absorber where it reacts with the sulfur oxides to produce magnesium sulfites and some magnesium sulfates. These reaction products are dewatered, dried and then transported to either an on- or off-site sulfuric acid plant where they are calcined to liberate the SO_2 which is used to produce the acid. The process can also be adapted to produce elemental sulfur. The regenerated MgO is shipped back for reuse in the system.

This system produces no waste sludge but requires that a market be available for disposal of substantial quantities of high-grade sulfuric acid. SO_2 removal efficiencies in excess of 90 percent are obtained.

Sodium Solution Scrubbing

A sodium sulfite solution is circulated through an absorber where it reacts with SO_2 in the flue gases to produce sodium bisulfite. This solution is fed to an evaporator which drives off the SO_2, forming a high concentration of SO_2 steam and a slurry of sodium sulfite crystals. The SO_2 gas stream can be used to produce either sulfuric acid or elemental sulfur. The slurry of sodium sulfite crystals is recirculated to the absorbing system. SO_2 efficiencies in excess of 90 percent can be obtained.

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4.0 INSTRUMENTATION, RECORDS, AND REPORTS

To determine compliance, the NSPS inspector will rely primarily upon the readings from the installed emission monitoring systems. However, for plants not covered by NSPS, the inspector will usually have to rely upon process or control equipment instrumentation plus facility records of fuel sulfur and ash contents. This section is designed to familiarize the inspector with emission-related instrumentation commonly encountered in process operation, emission controls, and emission monitoring. The type, location, and purpose of each instrument are described briefly; detailed theoretical principles of instrument operation are available from other literature sources.[1,2] Recordkeeping and reporting requirements of the NSPS are also outlined.

4.1 PROCESS INSTRUMENTATION

Large steam generators, such as those with heat inputs greater than 63 MM Kcal (250 MM BTU) per hour, usually display instrumentation on a control panel. Although the instruments are designed mainly to aid the boiler operator, several of them can also aid the inspector in determining whether the power plant is complying with regulations.

Steam Flow/Air Flow Recorder

The steam and air flow monitor is equipped with a circular or strip chart on which are recorded instantaneous values of steam and air. Air flow inputs must be proportioned properly to ensure complete fuel combustion and minimum uncontrolled particulate emissions. Steam flow values also serve as a check on heat input values (BTU) given to the inspector by utility personnel.

Oxygen (Combustion Gas) Recorder

The recorded amount of CO_2 or O_2 in the flue gas is significant in defining the status of the combustion process. For efficient combustion, O_2 values of 2 to 5 percent in the flue gases indicate a proper proportion of excess air. Lower amounts of oxygen indicate insufficient air, a condition that increases particulate concentrations and causes black smoke. Higher values of O_2 result in low furnace temperature (white smoke), or poor fuel atomization. In addition, the increased airflow tends to overload the control equipment. If a steam generator is using low excess air (e.g. less than 2 to 5 %) to reduce NO_x emissions, this will be indicated by the O_2 analyzer and can be used as a future compliance check (i.e., the boiler should be operated at approximately the same low excess air levels to minimize NO_x emissions).

Oil and Steam Pressure Recorders

Oil and steam pressure gages are located in supply lines leading to the burners. Although pressures and temperatures vary depending on boiler design and fuel properties, values should be between 120 and 180 psi pressure, and 170 and 220°F. Steam atomizing pressures should be about 15 psi higher than oil pressures.

Fan Amperage Meters

Gas volume changes are detected by amperage meters on the fan system. The gages serve as a check on air flow monitor values discussed earlier in this section.

Other Records

Performance standards require new or modified steam generators to record daily fuel rates and electrical generation. The facility should also maintain a record of fuel sulfur and ash contents. If low-sulfur coal is used for compliance purposes, a daily sulfur analysis, in accordance with Part §60.45 of 40 CFR 60, may be substituted for fuel monitoring requirements.

4.2 CONTROL DEVICE INSTRUMENTATION

The inspector can collect initial control device data when performance tests are performed. Comparison with data from later inspections should indicate whether the source is in compliance without further emission testing.

Control devices designed for new and modified steam generators include precipitators and scrubbers.

Electrostatic Precipitators

The inspector should record voltage, current, and spark rates from instrument gages usually located near the precipitator power supply.

A transformer converts incoming "primary" voltage (220 or 440 volts) to "secondary" kilovolts required by the precipitator unit. Secondary current and voltage readouts are in mA and kV, respectively. Gages may record primary or secondary voltages and currents, or both.

The spark rate meter is calibrated in sparks per minute. Low spark rates may be due to low power input.

Each section of precipitators has its own instrumentation. The inspector must record values from all sections. Control equipment manufacturers state acceptable values for electrostatic precipitator power requirements; spark rates between 50-100 sparks per minute usually indicate optimum particulate collection.

Scrubbers

When inspecting venturi scrubbers for particulate removal, the inspector should check the pressure drop across the venturi throat.

Sulfur dioxide scrubbing systems incorporate additional instrumentation. Essentially all systems will have an outlet SO_2 emissions monitor. In addition, most FGD systems have extensive instrumentation to measure pressure drops through various sections of the scrubbing trains, solids concentrations in scrubber make-up, hold and recirculation tanks, and pH of the scrubbing slurry. To a limited extent such instrumentation can be used to monitor performance but any significant departure from accepted or normal values of these parameters will lead to system upsets (e.g., plugging, loss of pH control) which will cause the system to be brought off-line anyway.

4.3 EMISSION MONITORING INSTRUMENTATION

Concentrations of particulate, sulfur dioxide, and nitrogen oxides must be continuously monitored and recorded. Specific requirements for coal-, oil-, and gas-fired steam generators are summarized in Section 2.2.

The NSPS inspector must be familiar with the various types of instrumentation and with methods of verifying the levels of pollutants indicated by the instruments.

4.3.1 Opacity Monitors

The photoelectric opacity monitor and recorder directly measures the attenuation of light passing through stack exhaust gas. As shown in Figure 4.1, transmissometers incorporate a light source on one side of the stack and a detector on the other side. Invisible plumes have a transmittance of 100 percent and an opacity of zero percent; opaque plumes attenuating all of the light have zero transmittance and 100 percent opacity. An electronic strip-chart recorder continuously records opacity values. Many models zero themselves automatically at regular intervals; this adjustment is indicated on the chart paper.

At present none of the opacity monitors meet NSPS daily calibration requirements. In any two-ended system the gas flow must be shut off to obtain a calibration for zero percent opacity. The instrument should be calibrated each time the unit is down. Inherent problems include dirty or scratched optics and changes in the detector and light source characteristics; these latter problems are minimized by automatic zeroing units.

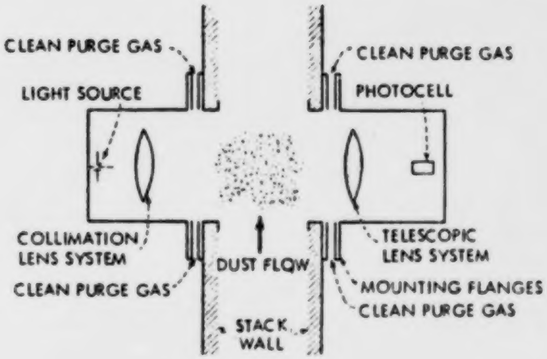

CLEAN PURGE GAS
LIGHT SOURCE
CLEAN PURGE GAS
PHOTOCELL
COLLIMATION LENS SYSTEM
CLEAN PURGE GAS
DUST FLOW
TELESCOPIC LENS SYSTEM
MOUNTING FLANGES
CLEAN PURGE GAS
STACK WALL

Figure 4.1 Light transmission system.

4.3.2 Sulfur Dioxide Instrumentation

Many types of instruments are in current use for continuous analysis of SO_2 gas, including spectrometers and electrochemical sensors. Wet chemical analyzers are not practical for stack monitoring, since they are subject to fouling by mist and particulates and to interference from unremoved gases and water vapor.

The spectrometer using the ultraviolet region of the SO_2 spectrum is the monitor most commonly used, since other types of monitors require withdrawl of a sample from the stack. The UV absorber uses the stack as its optical path and thereby provides cross-stack average measurements. The SO_2 absorption spectrum is matched against a reference pattern in such a way that other materials do not interfere.

Electrochemical instruments can detect both sulfur dioxide and nitrogen oxides. A fuel cell sensor generates an electric current by electro-catalytic oxidation or reduction of SO_2; the current is directly proportional to the SO_2 concentration in the sample of the gas stream. These sensors must be replaced periodically to provide accurate readings. The inspector can calibrate the instruments by inserting known concentrations of calibration gas into the analyzer. Two known concentrations can be carried in small sample cylinders and calibrations performed according to the manufacturer's specifications at operating temperatures and pressures. Erroneous SO_2 readings result from leaks and plugs in the lines and filters from coating of the lens. Periodic maintenance is required to remove dust, oil, and condensation from the system.

4.3.3 Nitrogen Oxides Instrumentation

The NSPS for NO_x emissions from new and modified steam generators apply to both NO and NO_2 although less than 5 percent of the NO_x is present as NO_2. Therefore, measurement of stack NO content is adequate for monitoring purposes (unless excessive "excess air" is introduced into the exhaust gas stream).

Nitrogen oxide instrumentation includes photometric and spectroscopic analyzers, electro-chemical methods, and chemiluminescent detectors. Wet-analyses instruments are not practical for in-stack monitoring.

Photometric and spectroscopic analyzers measure light transmission at a specific wavelength. Since these instruments depend upon light transmission, they may give erroneous readings as a result of absorption of radiation by particulate matter or condensates in combustion gases.

Electrochemical instruments were discussed above for monitoring sulfur dioxide. NO_x readings may be high as a result of the presence of SO_2. The inspector should note whether the sample inlet system has an absorber to remove SO_2 from the sample.

Nitric oxide is detected by the chemiluminescent reaction of NO with ozone-producing light. The intensity of the light, which is detected by a photomultiplier tube, is proportional to the NO concentration. The inspector can calibrate the instrument with standard concentrations of NO by techniques similar to those mentioned for SO_2 calibration.

4.4 FUEL ANALYSIS PROCEDURE

A representative fuel sample taken during a performance test of a coal- or oil-burning facility provides a sample for performing an ultimate analysis. Heating values are required to define emissions in terms of BTU heat input.

Although carbon, hydrogen, sulfur, nitrogen, and ash fractions are not directly needed, they do provide a material balance check of boiler gas volumes. In addition, emission estimates based on sulfur and ash percentages serve as useful companion information to source test emission data.

Samples can be removed from the feed coal before or after it enters the pulverizers. Placing the sample in sealed polyethylene bags prevents moisture from escaping so that accurate "dry basis" and "as received" values can be obtained. A total coal or oil sample of 1 to 2 quarts taken at half-hour test intervals constitutes a sufficient fuel sample for analysis.

4.5 FACILITY RECORDKEEPING REQUIREMENTS

Operators of new and modified steam generators are required to keep records of specific items. These items were discussed and summarized in Section 2. Additional items that must be recorded include combustion gas data (CO_2, O_2, or unburned combustibles), process data that influence NO_x emissions, and specific process and control device maintenance information.

Table 4.1 lists the items directly or indirectly associated with air pollutant emissions that should be recorded. The recording procedure, frequency, and accuracy of data are given for each parameter. The inspector can review records in either of two ways: he can complete his own at the time of his visit to the site, or he can have facility personnel complete a checklist and give it to him at the time of his inspection. The latter method appreciably reduces the time required of the inspector at each individual boiler facility. The six-part form presented in Table 4.2 can be completed in either manner.

Table 4.1 ITEMS TO BE RECORDED BY POWER PLANTS SUBJECT TO NSPS

Item	Recording procedure and frequency	Recordkeeping Accuracy	Remarks
Fuel Analysis			
* Sulfur	Daily	0.01%	State ASTM (F.R.) or ASME Method (coal PTC 3.2-1954; oil PTC 3.1-1958) or equiv. Avg. of 3 samples taken not less than 4 hrs. apart.
* Ash	Weekly	0.01%	State ASTM (F.R.) or ASME Method (coal PTC 3.2-1954; oil PTC 3.1-1958) or equiv. Avg. of 3 samples taken not less than 24 hrs. apart.
* Heating Value	Weekly	4 Signficant Figures	State ASTM (F.R.) or ASME Method (coal PTC 3.2-1954; oil PTC 3.1-1958) or equiv. Also report "as fired" to calculate BTU/hr) and dry (for C balance), also state whether method determined from Bomb or Seyler coal chart.
Process			
Steam Flow	See remarks	3 Significant Figures	Mark dates on strip or circular charts and keep.
Air Flow	See remarks	3 Significant Figures	Available for inspector.
* Fuel Rate	Record daily integral value. During startup, record fuel usage until unit is stabilized	4 Significant Figures	
* Average Electrical Output	Divide daily MW output by hours of operation	4 Significant Figures	
* Maximum Hourly Output	Record highest daily MW production and hour of occurrence	4 Significant Figures	
* Minimum Hourly Output	Record lowest daily MW production and hour of occurrence	4 Significant Figures	
Combustion Analysis	For gage instrumentation, record CO_2 and/or O_2 twice during 24 hr. period; read at anticipated high and low daily load for chart instrumentation, see remarks.		
CO_2		0.1%	Mark dates on strip charts and keep available for inspector.
O_2		0.1%	
Flue Gas Temperature	See remarks	Nearest Degree	Mark dates on strip charts and keep available for inspector.
Flue Gas Recirculation Rate	Read once daily	0.1 inch H_2O	
Oil Preheat Temperature	Read once daily	Nearest Degree	
Oil Preheat Pressure	Read once daily	Nearest psi	
Control Devices			Many control devices are designed in units or sections. In this case, records of each individual section is required.
ESP			
Spark Meter(s)	Read once daily	Sparks Per Minute	
Unit Voltage(s)	Read once daily	3 Significant Figures	
Unit Current(s)	Read once daily	3 Significant Figures	
Scrubber			
Water Rate	Record daily throughput and compute avg/minute	Gallons Per Minute	
Additive Rate	Record Daily total and compute pounds/day	Pounds Per Day	
pH	Read once daily	Nearest Tenth	
Pressure Drop	Record once daily	0.1 inch H_2O	

Table 4.1 (Continued). ITEMS TO BE RECORDED BY POWER PLANTS SUBJECT TO NSPS

Item	Recording procedure and frequency	Recordkeeping Accuracy	Remarks
Monitors			
* Particulate/Opacity	Read high value from chart per 8 hr. period; record amplitude and time	Nearest Percent	
* SO_2	Read high value from chart per 8 hr. period; record amplitude and time	Nearest ppm	These instruments detect ppm (by volume to volume). Records shall be kept in in these units since they cannot "be reduced to ... the applicable standard..." As stated by §60.45(f). This would involve computation of instantaneous fuel heating values. Heating values are required only on a weekly basis.
* NO_x	Record high value from chart per 8 hr period; record amplitude and time	Nearest ppm	
*Malfunctions, Startup	Frequency as required	As Required	A quarterly report of all startups and/or malfunctions which leas to emissions higher than applicable standards will be submitted on the 15th day following the end of the calendar quarter. The report shall include description of malfunction, date, duration, nature and cause, corrective actions and preventive measures, and values of emissions from pollutant monitors.
Maintenance and Calibration	State weekly history	As Required	
Monitors			
* Particulate/Opacity			
* SO_2			Calibration required daily or more frequent if specified by manufacturer.
* NO_x			
Instruments			Check air flow/steam flow monitor weekly. Check CO_2 and O_2 meters against fyrite or orsat results
Pulverizers/Feeders			Check coal sizing weekly per ASTM 410-38; ASME 3.2 1954.72 (stokers) and ASTM D 197-30; ASME 3.2 1954.84 (pulverizers)
Burners			Inspect weekly for plugging, poor atomization (higher atomization pressure) clean as required.
Control Device			

* Required by NSPS

Table 4.2 NSPS RECORDKEEPING DATA SHEETS

STEAM GENERATING FACILITIES

Company name____________________ Company plant code________________

Plant name____________________ Recordkeeping for week ended____________

PART I PROCESS DATA

Item Date							
Fuel Rate, lb, gal, ft^3/day							
Megawatts, average							
Megawatts, maximum							
Megawatts, minimum							

PART II FUEL ANALYSIS DATA

Date								
Sulfur analysis*	Sample A							
	Sample B							
	Sample C							
	Average							

Method used ☐ ASTM ☐ ASME ☐ Other (specify)________________

Item	Sample X	Date taken	Sample Y	Date taken	Sample Z	Date taken	Average
Ash							
Heating value							

Ash determination method ☐ ASTM ☐ ASME ☐ Other (specify)________________

HV determination method ☐ ASTM ☐ ASME ☐ Other (specify)________________

* Daily analysis only required when low-sulfur fuel is used in lieu of SO_2 instrumentation

Table 4.2 (Continued). NSPS RECORDKEEPING DATA SHEETS

STEAM GENERATING FACILITIES

PART III EMISSION MONITORING DATA

- Emission monitor data requires three daily values taken once per shift or 8 hour duration
- If plant operates less than 3 shifts per day or unit is down, write in "no operation."
- Define pollutant units (i.e., % opacity or transmittance, ppm, etc.)
- Disregard recordkeeping if instrument is equipped with a strip-chart recorder

Day & shift	Particulate/opacity		Sulfur dioxide		Nitrogen oxide	
	Time (24-hr clock)	Reading units	Time (24-hr clock)	Reading units	Time (24-hr clock)	Reading units

Table 4.2 (Continued). NSPS RECORDKEEPING DATA SHEETS STEAM GENERATING FACILITIES

PART IV. CONTROL DEVICE DATA

Check if applicable	Type of control device(s)	No. of units per boiler	Data required for each unit	Average value during acceptable performance test			
☐	Electrostatic Precipitator		Spark rate (sparks/min)				
			Voltage (kV)				
			Current (ma)				
☐	Scrubber		Water rate (gal/min, avg)				
			Additive rate (lb/day, avg)				
			Pressure drop (in. H_2)				
☐	Other (specify)						

Control device(s)	Data units	Date of collected data						

Table 4.2 (Continued). NSPS RECORDKEEPING DATA SHEETS STEAM GENERATING FACILITIES

PART V. MAINTENANCE AND CALIBRATION

Item	Date	Description of maintenance or calibration
Particulate/opacity monitor		
SO_2 monitor		
NO_2 monitor		
Fuel flow/air flow instrument		
CO_2 and/or O_2 monitor		
Fuel feed instrument		
Burners		
Control device		

Table 4.2 (Continued). NSPS RECORDKEEPING DATA SHEETS STEAM GENERATING FACILITIES

PART VI. START-UP AND MALFUNCTION HISTORY

Recordkeeping period year __________ quarter 1 2 3 4

Start-up or malfunction duration ____________________

Detailed explanation of start-up or malfunction ____________________

Corrective action taken ____________________

Preventive means adopted ____________________

Note: During total start-up or malfunction period record values of the following parameters at 15 minute intervals.

Time, 24 hr clock										
Steam flow, lb/hr										
Air flow, lb/hr										
Particulate/opacity, %										
SO_2, ppm										
NO_x, ppm										

REFERENCES FOR CHAPTER 4

1. Evans, R.K., Combustion Control, Power. December 1967.
2. The Babcock and Wilcox Company. Steam: Its Generation and Use, 1963.
3. Guidelines for the Selection and Operation of a Continuous Monitoring System for Continuous Emission Sources, EPA Contract No. 68-02-0226, Task 14 (Preliminary draft).
4. Performance Specifications for Stationary Source Monitoring Systems for Gas and Visible Emissions, EPA Report No. EPA 650/2-74-013 (Preliminary draft).

5.0 START-UP/SHUTDOWN/MALFUNCTIONS

Steam generating facilities are required to report measured or estimated emissions for each occurrence of a shutdown-start-up cycle and submit a written report following the end of each calendar quarter. The report shall include the nature and cause of any malfunction resulting in a shutdown, corrective actions taken, and preventive measures adopted.

5.1 FREQUENCY OF OCCURRENCES

Forced outages result from unpredicted malfunctions requiring immediate shutdown. Planned outages are required for routine maintenance and inspection. An accumulation of outage data for fossil-fuel-fired units is presented in Table 5.1.[1] The column "Total annual outages per unit per year" is the sum of all forced and planned outages. The table should serve only as a general guide for the occurrences of start-up, shutdown, and malfunctions.

Table 5.1 FREQUENCY OF SHUTDOWNS OF STEAM GENERATING FACILITIES

Unit size, MW	No. of units reviewed	Total annual outages per unit per year	Forced annual outages per unit per year
> 60	733	11	6
> 400	98	17	12

If a malfunction is related to the emissions control system, emissions may be in excess of NSPS until the problem is noticed and the unit is shutdown. Since many different malfunctions can occur, the duration of excess emissions cannot be predicted with any degree of reliability.

5.2 TYPES OF OCCURRENCES

Forced outage malfunctions, by definition, involve a shutdown-start-up cycle. Some malfunctions, however, can be resolved on-line and do not require a shutdown. In these instances a boiler may be "turned down" to as low as 10 percent of design load without appreciably increasing emissions.

Planned outages require complete shutdown of the unit to enable maintenance personnel to perform such tasks as slag cleanout, precipitator repair and boiler tube repair.

Some facilities find it desirable to use lower cost, less efficient units for peaking operations. Such units may be subject to intermittent service that requires start-up every weekday morning. New steam generators are not normally used as peaking units.

Discussions of start-up, shutdown, and malfunction occurrences follow.

Start-up

During start-up, particulate emissions and equivalent opacity will be higher than during normal operation and will persist until operation is stabilized. Figure 5.1 shows the time required for various boiler sizes to reach stable load. A steam generator may have unique characteristics that result in significant deviation from the graph.

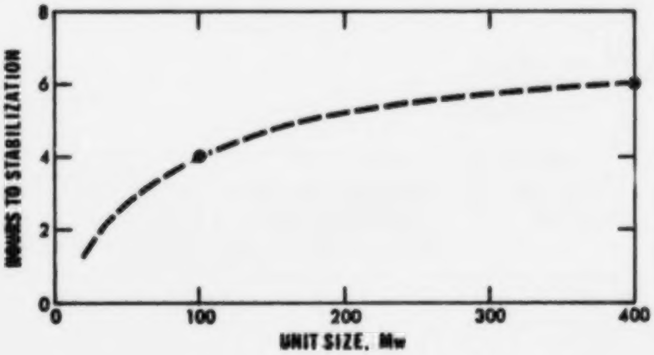


Figure 5.1 Required start-up time to achieve on-line load demand for fossil-fuel-fired steam generators.

Shutdown

Air pollutant emissions are not a problem during boiler shutdown. The firebox interior aids in fuel burnout after the boiler is turned off. The units can be shutdown very quickly and easily.

Malfunctions

Malfunctions result from either equipment breakdown or operator error; however, not all malfunctions substantially increase emissions. Those that can result in excessive emissions are presented below:

- improper combustion air flow due to faulty fans or dampers
- air preheater system (if used) not sufficiently heating air
- irregular fuel flow to coal mills or oil or gas burners
- firebox flame out (usually detected on control panel)
- emission control device malfunction.

Air flow malfunctions occur if fan and damper components fail, or when operators inadvertently set dampers at improper positions. Shutdowns associated with fuel flow problems frequently result from negligent maintenance, such as coked or burned burner impellers or plugged oil tips.

Many malfunctions are signalled immediately by safety features incorporated in the control panel. Excess temperatures and/or pressures, burner flame outs, and improper fuel feed rates are malfunctions that are signalled to the operator.

Steam generator load swings are necessary to meet output demand. Although not defined or covered as start-up, shutdown, or malfunction, load change often results in excessive particulate emissions. The high rate of emissions can last for several minutes until air flow and fuel flow are equilibrated. Of course, careless operation will increase both the excessive emission rate and duration.

Precipitator malfunctions are usually due to some failure which affects the capability of supplying power to one or more of the precipitator sections. Such failures can be caused by broken wires and insulators, power supply or control malfunctions. Whether or not particulate emission standards are exceeded when one or more sections are de-energized depends upon the precipitator design.

Failure of the ash removal system to empty an ash hopper can increase particulate emissions by causing a section to short-out (when the fly ash builds up to the point where it hits the electrodes) and through reintrainment of the fly ash in the hopper. Improper bin design can create a "rat-hole" condition where a hole is created through the bed of ash in a hopper rather than the entire hopper emptying.

Flue gas desulfurization systems can malfunction for a variety of reasons. The problems include scaling, plugging, corrosion or erosion, as well as failure of individual components. These problems can be resolved in the design, start-up, or debugging phases of FGD system operation. Reliability of the system should be about the same as the boiler (on the order of 90%). If the reliability of the system is less than this, the inspector should have the utility categorize the problems, the percent of time the system is down due to each problem, the specific corrective action which will be taken, and the timetable for such corrective action.

REFERENCES FOR CHAPTER 5

1. Letter to EPA Division of Stationary Source Enforcement (Attention: Mr. Megonnell) by Edison Electric Institute (W. D. Crawford) dated October 10, 1972.

6.0 PERFORMANCE TEST

During the performance test the inspector must observe process and control equipment operation to ensure that the tests are conducted under the proper operating conditions, as well as the emission tests to determine whether proper test procedures are followed. The purpose of the performance test is to determine whether the emission standards will be met when the boiler is operating under normally encountered conditions that create the maximum emission rate. In addition, values for key process and control equipment operating parameters can be obtained to form a basis for comparison on future plant inspections.

Section 6.1 covers the inspector's responsibilities in preparing for the performance test. Section 6.2 describes the steam generator and control equipment operating conditions under which tests should be conducted. Section 6.3 describes the source test data the inspector should obtain to determine whether the test was properly conducted. An inspection checklist is presented in Section 6.4 which summarizes all process and test parameters to be recorded during the performance test.

6.1 PRETEST PROCEDURES

Although the new source performance standards stipulate exact procedures for compliance, facility personnel may misunderstand or not be aware of parts of the regulations. The inspector should therefore arrange a meeting with plant personnel to review details of the standards and the testing procedures prior to the actual performance test. The inspector provides copies of the performance standards at the meeting. The inspector informs all parties of the latest revisions to the standards, such as the proposal and possible promulgation of the September 11, 1974 rules.

The inspector must also survey the ductwork for test port locations. The location of a clean-up area should be agreed upon by all parties prior to the test date. During a tour of the power plant, the inspector determines whether additional inspection personnel are required to monitor the process, sampling site, and exhaust stack.

The inspector must ensure that management understands that performance tests are valid only if performed while the facility is operating at representative performance. At this time, the parties should agree on the parameters constituting "representative performance." The inspector should also determine which testing firm is to perform the tests and, if no representative of the firm attends the meeting, contact the firm to ensure that tests are run in accordance with procedures outlined in 40 CFR 60. The chief purpose of the pretest meeting is to outline clearly for all concerned parties the purpose of the tests and the required test procedures.

6.2 PROCESS AND CONTROL EQUIPMENT OPERATING CONDITIONS

Important process operating emission control device parameters for which values must be established before the tests are conducted are listed below:

- steam production rate
- fuel composition (ash, sulfur)
- excess air rate
- flue gas recirculation rate (if applicable)
- number of electrostatic precipitator sections in operation
- scrubber pressure drop and L/G ratio (particulate emission control)

Parameters of secondary importance are:

- soot blowing frequency
- oil preheat temperature and burner atomizing pressures

The importance of each of these is briefly described below:

Steam production rate - As required by Part §60.8, the tests should be conducted at representative performance conditions. Boiler capacities are typically rated in terms of ascending output as rated or name-plate, maximum continuous, and peak. Peak capacity is the maximum output the boiler can and will produce for short periods of time, usually measured in terms of a few hours. Tests should be conducted at the maximum continuous capacity since it is not practical to conduct the particulate tests at the peak value and tests for all three pollutants should be conducted under the same conditions. Furthermore, boilers are operated only infrequently at peak operating conditions.

Fuel composition - Particulate emissions from an electrostatic precipitator on a coal-fired boiler should be tested with coal of the lowest sulfur content, and to the extent possible given the previous constraint, the highest ash content that the plant anticipates using.

Excess air rate - If the plant uses low excess air firing to meet the NO_x emission limitations, then the tests should be conducted at the excess air rate that the plant anticipates using. Particulate emission tests must be conducted at this excess air level since particulate emissions can increase as excess air levels are reduced.

Flue gas recirculation rate - The percentage of flue gas recirculated should be set if this method is used to minimize NO_x emissions.

Number of electrostatic precipitator sections - The precipitator may be designed to meet the standard with one or more sections de-energized. The precipitators are to be operated during the compliance test with any specific sections de-energized that were designed as a safety factor with respect to emission standards.

Particulate emission scrubber pressure drop - Since scrubber efficiency for particulate emissions control decreases with decreasing scrubber pressure drop, the particulate emission tests should be conducted with the scrubber pressure drop (consistent with boiler load conditions identified above) at the lowest value under which the facility anticipates operating.

For boilers equipped with intermittent blowing, the frequency of soot blowing during the particulate emission tests must be proportioned to the soot blowing during the representative performance.

6.3 EMISSION TEST OBSERVATIONS

Emission tests and opacity determinations are conducted by qualified emission testing personnel. The inspector is responsible for ensuring that all pertinent data are collected, that the field procedures and equipment meets CFR, and that the power plant is run at representative performance during all sampling operations. A technician or engineer qualified by EPA Method 9 reads visible emissions, as described in Part 60.11(b). The visible emission form, Appendix B, is the appropriate form for recording visible emissions.

The inspector's degree of surveillance of the stack sampling team depends on the confidence of the inspector and qualifications of the test personnel. Even if the inspector has complete trust in the sampling crew, the following task should always be performed:

- Record duct dimensions (both inside and outside) and location of sample ports.

- Check the number of ports at the sampling site and examine the ducting for the nearest upstream and downstream obstructions. Ask the crew leader how many total points will be traversed and check with Figure 1.1 in 40 CFR 60 to determine whether the stream will be properly sampled.

- Note whether the crew runs a preliminary traverse, and if so, inquire what nozzle diameter is selected. (Isokinetic sampling is a function of nozzle size.)

- Check to ensure that the moisture content of the gas stream is determined by Method 4 or an equivalent method such as drying tubes or volumetric condensers; assumption of the moisture content is not allowed.

- Observe the leak test of the sampling train. The allowable leak rate is given in Method 5. Leakage results in lower concentrations than are actually present. Be next to the dry gas meter during the leak check, note whether the meter hand is moving. (The more the hand is moving, the greater the leakage.) Leak checks must also be made if the train is disassembled during the run to change a filter or to replace any component.

- Ensure that a fuel sample and gas analysis are taken to calculate a material balance. This serves as a check of flow rates obtained by pitot tube readings.

- Record dry gas meter readings before and after test.

- Record average velocity head and temperatures in duct during test.

- If impingers are used during test, observe whether they are bubbling. If they are not, the sampling train is either plugged or disconnected from the pump.

- Check the cleaning procedure for the front half of the train. Careless removal of filters or cleaning of probes will result in lower calculated emissions. Look for broken glass from probes or connectors. Test is void if glass probe was broken during test. If glass connectors are broken in transport from sampling site to clean-up area, test is still valid. Be sure identification labels are properly attached to collection containers. The probe should be brushed and rinsed with acetone thoroughly to remove all particulates. The probe should be visually inspected after cleaning to ascertain that all particulates have been removed.

- Check control panel periodically as outlined.

- For NO_x tests, check the mercury manometer to ensure that flask is evacuated to at least 20 inches Hg absolute pressure. If this level cannot be reached, a larger pump is needed.

- For NO_x and SO_2 test, note whether the gas stream has a negative or positive pressure. If a negative pressure is present, precautions are needed (i.e., long probe, sealed port) to ensure that no ambient air passed through the train, which would result in calculated emissions lower than those actually present. The Federal Register states that the duct sampling point cannot be less than 3 feet from the duct wall if the cross-sectional area is greater than 50 square feet.

- Observe gas analysis procedure for determining CO_2. Technician should take at least three samples before averaging readings. Variations greater than 0.5 percent (grab sample) or 0.2 percent (integrated sample) indicate gas mixture was not thoroughly bubbled in reagents. Ask technician or crew leader when new reagents were added to apparatus.

The inspector's role regarding emission monitoring instruments is summarized below. The operating principles of the instruments described previously are complex, and the probability exists of encountering undetected errors. The inspector can only be responsible for carrying out the following steps:

- Note values on emission monitoring instrument. Gaseous concentrations of SO_2 and NO_x in ppm and lb emitted per MM BTU are related during the compliance test. NSPS are in terms of the latter units. During future tests, only the ppm values are recorded from the monitors.

- Check previous history of calibrations, malfunctions, cleaning, repair, and trends of recorded emissions. Regulations state that emission monitoring instruments must be calibrated at least once per 24 hour operating period. The inspector should note the calibration frequency, and the error in readings prior to calibration. If the instrument readout drifts greatly, the inspector should ask plant personnel to contact the manufacturer for service.

Regulations also require that emissions be read to within ± 20 percent with a 95 percent confidence level. The inspector should check instrument accuracy with manufacturer's specifications.

6.4 PERFORMANCE TEST CHECKLIST

The inspector must observe the steam process and emission tests simultaneously to ensure that data used in determining plant performance are valid. He should also complete a performance checklist, outlined on the following page. If the inspector observes any additional parameters the facility records that are directly related to emissions, they should also be recorded.

In the event of a malfunction or upset, the enforcement officer must inform the test crew leader that the sampling trains are to be shut-off and removed from the ducts as quickly as possible. If process changes or deviations occur, the inspector is responsible for instructing the sampling personnel whether to proceed with the run or temporarily stop the test.

The enforcement officer keeps a log of any abnormal operation, time of occurance, and return to representative conditions. After reviewing emission test results, he can decide whether the run is valid.

When the emission testing firm submits a test report, results must be carefully checked and compared with data recorded on the inspector's checklist. Thus, the checklist both provides verification that the tests were properly conducted and serves as the baseline for future inspections of the facility. A suggested format for the contents of the emission tests are presented in Appendix C.

Table 6.1

NSPS INSPECTION CHECKLIST FOR STEAM-ELECTRIC GENERATORS DURING PERFORMANCE TEST

COMPANY NAME ____
SOURCE CODE NUMBER ____
COMPANY ADDRESS ____
NAME OF PLANT CONTACT _____________________________________
UNIT DESIGNATION (TO BE TESTED) ___________________________
STEAM CAPACITY ______________________________________ MM BTU/hr
TURBOGENERATING CAPACITY ____________________________ megawatts
INITIAL START-UP DATE _____________________________________
REPRESENTATIVE PERFORMANCE ACHIEVEMENT DATE _______________
TEST DATE ____

A. STEAM GENERATOR CHARACTERISTICS (See Plant Engineer)

Fuel Type	Percentage %
☐ Coal	____________
☐ Oil	____________
☐ Gas	____________

Firing Type

- ☐ Front Wall
- ☐ Opposed Wall
- ☐ Vertical
- ☐ Tangential or Corner

Boiler Characteristics

- ☐ Fly Ash Recirculation
- ☐ Staged Firing

APC Device Type

- ☐ Scrubber
- ☐ ESP

NSPS INSPECTION CHECKLIST (Continued)

Heat Input

☐ Fuel Feed Meter
☐ Heat Rate Calculation

Fuel Analysis Source ____________________

Heating Value ____________ BTU lb gal. ft^3

Sulfur Content ____________ %

Ash Content ____________ %

NSPS INSPECTION CHECKLIST (Continued)

B. INSTRUMENTATION DATA

Record the following data every 30 minutes during performance test.

Parameter	Units	Values				
Recording Time	24 hr					
Steam Load	lb/hr					
Air Load	lb/hr					
CO_2	%					
O_2	%					
Gas Exhaust Temp.	°F					
Flue Gas Recirc. Draft	in. H_2O					
Oil Preheat Temp.	°F					
Oil Pressure	psig					
Atomizing Pressure	psig					
Heat Input						
Fuel Feed	lb, gal., ft^3/hr					
Heat Rate	MM BTU/hr					
Soot Blowing Time	minutes					
Monitors						
Opacity	%					
SO_2	*					
NO_x	*					
APC Device						
Spark Rate	sparks/min					
Unit Voltage	kv or v					
Unit Current	ma or a					
pH						
Liquid Solvent Rate	gal./min					
Pressure Drop	in. H_2O					
Additive Rate	lb/hr					
Stack Plume	% opacity					

* Indicate ppm or other units.

NSPS INSPECTION CHECKLIST (Continued)

C. PRETEST DATA (SEE SAMPLING TEAM FIELD LEADER)

TEST COMPANY ______________________________

FIELD LEADER ______________________________

DUCT DIMENSIONS ________ in. x ________ in.; Area ________ ft^2

NEAREST UPSTREAM OBSTRUCTION ____________ ft

NEAREST DOWNSTREAM OBSTRUCTION ____________ ft

NO. OF SAMPLING PORTS ____________

NO. OF SAMPLING POINTS ____________

NO. OF SAMPLING POINTS REQUIRED FROM FIGURE 1.1 IN 40 CFR 60 ____________

D1. PARTICULATE PERFORMANCE TEST

TEST NO. ________ START TIME ________ FINISH TIME ________

	Yes	No
Preliminary Traverse Run (Method 1) Chosen Nozzle Diameter ________ in.	☐	☐
Moisture Determination (Method 4) Percent Moisture ________ ml Collected/Gas Volume ____ ml ____ ft^3	☐	☐
Train Leak Check	☐	☐
Fuel Sample Taken	☐	☐

Dry Gas Meter Reading Before Test ______ ft^3 @ ________ (time)

Dry Gas Meter Reading After Test ______ ft^3 @ ________ (time)

Volume Sampled ______ ft^3

Test Duration ______________ minutes

Average of Meter Orifice Pressure Drop __________ inches of H_2O

Average Duct Temperature ______________ °F

Velocity Head at Sampling Point ________ inches H_2O

Meter ΔH@* ________

Repetition Start Time ________

Repetition Finish Time ________

D2. SO_2 PERFORMANCE TEST

Test ____________ Repetition ____________

Duct Static Pressure ☐ Positive ☐ Negative

Port Protection Against Air Leakage ☐ Yes ☐ No

Probe Length ________ inches

D3. NO_x PERFORMANCE TEST

Test ____________ Repetition ____________

Duct Static Pressure ☐ Positive ☐ Negative

Port Protection Against Air Leakage ☐ Yes ☐ No

Mercury Manometer Head

Left Leg ________ in. Hg
Right Leg ________ in. Hg
Total Vacuum ________ in. Hg

E. CLEANUP PROCEDURE

Filter Condition	☐ Dry		☐ Wet
Probes	☐ Unbroken		☐ Broken
Glass Connectors	☐ Unbroken		☐ Broken
Cleanup Sample Spillage	☐ None	☐ Slight	☐ Major
Sample Bottle Identification	☐ Yes		☐ No
Acetone Blank Taken	☐ Yes		☐ No
NO_x Flasks Shaken Adequately	☐ Yes		☐ No

* Orifice pressure differential pumping 0.75 ft^3 of dry air at standard conditions.

REFERENCES FOR CHAPTER 6

1. Emission Testing Compliance Manual, PEDCo-Environmental Specialists, Inc., EPA Contract No. 68-02-0237, Task No. 19, August, 1974.

7.0 INSPECTION PROCEDURES

The inspector's periodic visits will enable him to determine the plant emission control status. These subsequent inspections, described in Section 7.1, are as rigorous as the orignial performance inspection. An inspection checklist is prepared in Section 7.2. Section 7.3 describes follow-up procedures after completing a review of the steam generator.

7.1 FUTURE INSPECTION PROCEDURES

The inspector's frequency of future visits is governed by each agency's policy. A quarterly inspection is recommended unless malfunctions or complaints dictate more frequent inspections.

Major emphasis of the inspection is placed upon checking facility records and emission monitors. Records reveal whether the facility is in compliance between inspections. Properly functioning NO_x and SO_2 instruments quickly indicate gaseous emission levels. Control device inspection will give an indication of particulate emissions.

The following procedure should be followed in the order shown whenever possible. The format enables the inspector to tour the plant and monitor instruments under actual conditions. Any questionable areas can be investigated later by looking at records after touring the facility.

OUTSIDE OBSERVATIONS

- Note plume opacity and color. Opacities greater than 20 percent are in violation.

EMISSION MONITORS

- Check automatic zero.
- Check calibration of instrument using calibrated gas cylinders.

CONTROL EQUIPMENT

- Read gages on precipitator indicating power input and spark rate.

- Read pressure drop gages on scrubbers used for particulate emission control.

RECORDS

- Scan emission monitoring records; note each occurrence with corresponding level when opacity, SO_2 and NO_x values are over standards. (Gas sampling instruments read concentrations in ppm. Appendix D contains graphs for converting ppm values to lb/MM BTU). Standards for opacity, SO_2 and NO_x are shown in Table 2.5. Sulfur dioxide allowable standards are approximately 600 ppm for coal and 400 ppm for oil usage. If NO_x concentrations of 400 ppm for coal, 200 ppm for oil, and 150 ppm for natural gas are exceeded, the steam generator is in violation of NSPS.

- Check calibration records. Instruments must be zeroed and calibrated daily.

- Scan fuel records, noting instances of sulfur and ash over values stated below. Fuel analyses must be performed at least once per week on representative coal samples. Steam generators attempting to achieve SO_2 standards by burning low-sulfur fuel have the option of analyzing and recording fuel constituents daily, or monitoring SO_2. Plants attempting to meet SO_2 standards by burning low-sulfur fuel must use coal or oil with a sulfur content less than 0.75[a] and 0.8 percent,[b] respectively. Ash content of coal must be similar to values during performance test.

- Review steam flow or electrical output records to determine whether unit capacity was exceeded. Fuel burning rate, electrical output, and hourly generation must be measured and recorded daily. Note values and frequency occurrence of steam or electrical generation over that during the performance test.

- Scan records of control device performance for (ESP) power requirements and (scrubber) pressure drops. Steam generators are not required to maintain control device records; records should be kept in a format similar to the one shown in Figure 4.2. Power pressure losses are indicative of performance degradation.

- Review records of malfunction. Note the number of identical occurrences and the action taken to alleviate future occurrences.

---

[a] Assumes 12,500 BTU/lb

[b] Assumes 15,000 BTU/gal

7.2 INSPECTION CHECKLIST

An inspection form, Table 7.1, follows which is derived from procedures in Section 7.1.

7.3 INSPECTION FOLLOW-UP PROCEDURES

The inspector's affiliations may be with a Federal, state or local agency. Interagency communications are necessary to keep personnel aware of the status of new steam generators.

If the inspector has evidence to cite the facility after a tour of the grounds, he should precisely state the reasons on the citation. A citation at this point can only be given for definite violations or failure to keep required records. Table 7.2 outlines follow-up procedures after inspecting the plant and reviewing records. The guidelines are for general situations; unique circumstances may be encountered that call for different action.

Table 7.1

NSPS INSPECTION CHECKLIST FOR STEAM-ELECTRIC GENERATORS AFTER PERFORMANCE TEST

COMPANY NAME______________________________

SOURCE CODE NUMBER________________________

COMPANY ADDRESS___________________________

NAME OF PLANT CONTACT______________________

UNIT DESIGNATION__________________________

STEAM CAPACITY____________________________

TURBOGENERATING CAPACITY___________________

INSPECTION DATE___________________________

A. PRE-ENTRY OBSERVATIONS

Time __________________

Stack Plume

Equivalent Opacity (circle one):
0 10 20 30 40 50 75

Opacity Regulation ☐ in compliance
☐ not in compliance

Smoke Color __________________

B. EMISSION MONITORS

Time __________________

Concentrations

☐Transmittance or ☐Opacity __________ %

Sulfur Dioxide __________ ppm

Nitrogen Oxides __________ ppm

Calibration

	Gas conc. (ppm)	Gas pressure (psig)	Monitor readout (ppm)	Satis.	Unsat.
SO_2	______	______	______	☐	☐
NO_x	______	______	______	☐	☐

NSPS INSPECTION CHECKLIST (Continued)

C. CONTROL EQUIPMENT

☐ ELECTROSTATIC PRECIPITATOR

SECTION	1	2	3	4
Primary current (amps)				
Primary voltage (volts)				
Secondary current (ma)				
Secondary voltage (kv)				
Spark rate (spk/min)				

☐ SCRUBBER

SECTION	1	2	3	4
Pressure drop across scrubber (in. H_2O)				

ADDITIONAL OBSERVATIONS: ____________________

NSPS INSPECTION CHECKLIST (Continued)

D. RECORDS

Comparison parameters	Units	Source test value	Values over source test	date													Approximate allowable value
Opacity Monitor	%																20% opacity
NO_x Monitor	ppm																500 ppm coal; 200 ppm oil; 150 ppm gas
SO_2 Monitor	ppm																600 ppm coal; 400 ppm oil
Fuel Sulfur Content	% by wt.																>1.0% coal; >0.81% oil*
Fuel Ash Content	% by wt.																fn of APC device efficiency
Steam Flow, MM lb/hr/ Electric Generator, kw																	
Control device power (kV,mA) or ΔP (in. H_2O)																	

MALFUNCTIONS

Date	Description	Max. monitor readings			Repetitious occurrences				
		Opacity	NO_x	SO_2	Dates				

RECORDKEEPING STATUS.

	Yes	No	
Are instruments zeroed daily?	☐	☐	If no, note maximum interval ________
Are instruments calibrated daily?	☐	☐	If no, note maximum interval ________
Are fuel samples analyzed weekly for ash and sulfur content?	☐	☐	If no, note maximum interval ________
Are fuel samples analyzed daily for sulfur content if generator has no SO_2 control system?	☐	☐	If no, note maximum interval ________
Are fuel burning rate, electrical output, and hourly electrical generation recorded daily?	☐	☐	If no, note maximum interval ________

* Steam generators attempting to meet SO_2 standards by burning low sulfur fuel.

Table 7.2 FOLLOW-UP PROCEDURES AFTER INSPECTING STEAM GENERATING FACILITY

Compliance parameter	Course of action
Visual emissions	The November 12, 1974 Federal Register states that EPA is in the process of defining a method to enforce opacity standards, such as specifying the number of readings per hour above the opacity standard that would constitute a violation.
Opacity, SO_2, NO_x monitors	a) Not in operation - issue citation
	b) Not properly calibrated or zeroed - advise plant personnel to implement a satisfactory program which might include services of outside consultants.
Control equipment instrumentation	a) Not in operation - request in follow-up letter schedule to repair instruments.
	b) Values indicating unit out of compliance - Determine reasons - have plant take appropriate corrective action.
Records	a) Not kept - Issue citation
	b) Values indicating plant is out of compliance:
	i. monitors - If SO_2 and/or NO_x standards are exceeded more than 5 times a month for intervals less than 4 hours, issue citation.
	- If SO_2 and/or NO_x standard is exceeded more than 8 continuous hours, issue citation
	- If opacity standard is ever exceeded for more than 2 continuous hours, issue citation.
	ii. fuel records - If ash/sulfur is frequently over values during performance test, determine reason.
	iii. generating capacity - Disregard short-term peak loads. If electrical output/fuel usage is consistently higher than emission test values, request another performance test.
	c) Daily instrument zero/calibration - Issue citation if instruments are not zeroed and calibrated within 3 or more consecutive days.
	d) Fuel analysis - Units without SO_2 control equipment must analyze fuel daily.
	e) Malfunction records - If complete information (time, levels, malfunction description, problem correction methods) is not recorded for all malfunctions, issue citation.

APPENDIX A

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

CODE OF FEDERAL REGULATIONS

(See 40 CFR 60 for complete
sampling procedures)

Chapter 1 - Environmental Protection Agency

SUBCHAPTER C - AIR PROGRAMS

PART 60 - STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart A - General Provisions

§60.1 Applicability.

The provisions of this part apply to the owner or operator of any stationary source which contains an affected facility the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of any proposed standard) applicable to such facility.

§60.2 Definitions.

As used in this part, all terms not defined herein shall have the meaning given them in the Act:

(a) "Act" means the Clean Air Act (42 U.S.C. 1857 et seq., as amended by Public Law 91-604, 84 Stat. 1676).

(b) "Administrator" means the Administrator of the Environmental Protection Agency or his authorized representative.

(c) "Standard" means a standard of performance proposed or promulgated under this part.

(d) "Stationary source" means any building, structure, facility, or installation which emits or may emit any air pollutant.

(e) "Affected facility" means, with reference to a stationary source, any apparatus to which a standard is applicable.

(f) "Owner or operator" means any person who owns, leases, operates, controls, or supervises an affected facility or a stationary source of which an affected facility is a part.

(g) "Construction" means fabrication, erection, or installation of an affected facility.

(h) "Modification" means any physical change in, or change in the method of operation of, an affected facility which increases the amount of any air pollutant (to which a standard applies) emitted by such facility or which results in the emission of any air pollutant (to which a standard applies) not previously emitted, except that:

(1) Routine maintenance, repair, and replacement shall not be considered physical changes, and

(2) The following shall not be considered a change in the method of operation:

(i) An increase in the production rate, if such increase does not exceed the operating design capacity of the affected facility;

(ii) An increase in hours of operation;

(iii) Use of an alternative fuel or raw material if, prior to the date any standard under this part becomes applicable to such facility, as provided by §60.1, the affected facility is designed to accomodate such alternative use.

(i) "Commenced" means, with respect to the definition of "new source" in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

(j) "Opacity" means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

(k) "Nitrogen oxides" means all oxides of nitrogen except nitrous oxide, as measured by test methods set forth in this part.

(l) "Standard conditions" means a temperature of 20°C (68°F) and a pressure of 760 mm of Hg (29.92 in. of Hg).

(m) "Proportional sampling" means sampling at a rate that produces a constant ratio of sampling rate to stack gas flow rate.

(n) "Isokinetic sampling" means sampling in which the linear velocity of the gas entering the sampling nozzle is equal to that of the undisturbed gas stream at the sample point.

(o) "Start-up" means the setting in operation of an affected facility for any purpose.

(p) "Shutdown" means the cessation of operation of an affected facility for any purpose.

(q) "Malfunction" means any sudden and unavoidable failure of air pollution control equipment or process equipment or of a process to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

(r) "Hourly period" means any 60 minute period commencing on the hour.

(s) "Reference method" means any method of sampling and analyzing for an air pollutant as described in Appendix A to this part.

(t) "Equivalent method" means any method of sampling and analyzing for an air pollutant which have been demonstrated to the Administrator's satisfaction to have a consistent and quantitatively known relationship to the reference methods, under specified conditions.

(u) "Alternative method" means any method of sampling and analyzing for an air pollutant which is not a reference or equivalent method but which has been demonstrated to the Administrator's satisfaction to, in specific cases, produce results adequate for his determination of compliance.

(v) "Particulate matter" means any finely divided solid or liquid material, other than uncombined water, as measured by Method 5 of Appendix A to this part or an equivalent or alternative method.

(w) "Run" means the net period of time during which an emission sample is collected. Unless otherwise specified, a run may be either intermittent or continuous within the limits of good engineering practice.

§60.4 Address.

All requests, applications, submittals, and other communications to the Administrator pursuant to this part shall be submitted in duplicate and addressed to the appropriate Regional Office of the Environmental Protection Agency, to the attention of the Director, Enforcement Division.

§60.5 Determination of construction or modification.

When requested to do so by an owner or operator, the Administrator will make a determination of whether actions taken or intended to be taken by such owner or operator constitute construction or modification or the commencement thereof within the meaning of this part.

§60.6 Review of plans.

(a) When requested to do so by an owner or operator, the Administrator will review plans for construction or modification for the purpose of providing technical advice to the owner or operator.

(b)(1) A separate request shall be submitted for each construction or modification project.

(2) Each request shall identify the location of such project, and be accompanied by technical information describing the proposed nature, size, design, and method of

operation of each affected facility involved in such project, including information on any equipment to be used for measurement or control of emissions.

(c) Neither a request for plans review nor advice furnished by the Administrator in response to such request shall (1) relieve an owner or operator of legal responsibility for compliance with any provision of this part or of any applicable State or local requirement, or (2) prevent the Administrator from implementing or enforcing any provision of this part or taking any other action authorized by the Act.

§60.7 Notification and record keeping.

(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification as follows:

(1) A notification of the anticipated date of initial start-up of an affected facility not more than 60 days or less than 30 days prior to such date.

(2) A notification of the actual date of initial start-up of an affected facility within 15 days after such date.

(b) Any owner or operator subject to the provisions of this part shall maintain for a period of 2 years a record of the occurrence and duration of any start-up, shutdown, or malfunction in operation of any affected facility.

(c) A written report of excess emissions as defined in applicable subparts shall be submitted to the Administrator by each owner or operator for each calendar quarter. The report shall include the magnitude of excess emissions as measured by the required monitoring equipment reduced to the units of the applicable standard, the date, and time of commencement and completion of each period of excess emissions. Periods of excess emissions due to start-up, shutdown, and malfunction shall be specifically identified. The nature and cause of any malfunction (if known), the corrective action taken, or preventive measures adopted shall be reported. Each quarterly report is due by the 30th day following the end of the calendar quarter. Reports are not required for any quarter unless there have been periods of excess emissions.

(d) Any owner or operator subject to the provisions of this part shall maintain a file of all measurements, including monitoring and performance testing measurements, and all other reports and records required by all applicable subparts. Any such instruments, reports and records shall be retained for at least 2 years following the date of such measurements, reports, and records.

§60.8 Performance tests.

(a) Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial start-up of such facility and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator with a written report of the results of such performance test(s).

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart unless the Administrator (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, (3) approves the use of an alternative method the results of which he has determined to be adequate for indicating whether a specific source is in compliance, or (4) waives the requirement for performance tests because the owner or operator of a source has demonstrated by other means to the Administrator's satisfaction that the affected facility is in compliance with the standard. Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under section 114 of the Act.

(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of start-up, shutdown, and malfunction shall not constitute representative conditions of performance tests unless otherwise specified in the applicable standard.

(d) The owner and operator of an affected facility shall provide the Administrator 30 days prior notice of the performance test to afford the Administrator the opportunity to have an observer present.

(e) The owner or operator of an affected facility shall provide or cause to be provided, performance testing facilities as follows:

(1) Sampling ports adequate for test methods applicable to such facility.

(2) Safe sampling platform(s).

(3) Safe access to sampling platform(s).

(4) Utilities for sampling and testing equipment.

(f) Each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discon-conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.

§60.9 Availability of information.

(a) Emission data provided to, or otherwise obtained by, the Administrator in accordance with the provisions of this part shall be available to the public.

(b) Except as provided in paragraph (a) of this section, any records, reports, or information provided to, or otherwise obtained by, the Administrator in accordance with the provisions of this part shall be available to the public, except that (1) upon a showing satisfactorily to the Administrator by any person that such records, reports, or information, or particular part thereof (other than emission data), if made public, would divulge methods or processes entitled to protection as trade secrets of such person, the Administrator shall consider such records, reports, or information, or particular part thereof, confidential in accordance with the purposes of section 1905 of title 18 of the United States Code, except that such records, reports, or information, or particular part thereof, may be disclosed to other officers, employees, or authorized representatives of the United States concerned with carrying out the provisions of the Act or when relevant in any proceeding under the Act; and (2) information received by the Administrator solely for the purposes of §60.5 and §60.8 shall not be disclosed if it is so identified by the owner or operator as being a trade secret or commercial or financial information which such owner or operator considers confidential.

§60.10 State authority.

The provisions of this part shall not be construed in any manner to preclude any State or political subdivision thereof from:

(a) Adopting and enforcing any emission standard or limitation applicable to an affected facility, provided that such emission standard or limitation is not less stringent than the standard applicable to such facility.

(b) Requiring the owner or operator of an affected facility to obtain permits, licenses, or approvals prior to initiating construction, modification, or operation of such facility.

§60.11 Compliance with standards and maintenance requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined only by performance tests established by §60.8.

(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Reference Method 9 in Appendix A of this part. Opacity readings of portions of plumes which contain condensed, uncombined water vapor shall not be used for purposes of determining compliance with opacity standards. The results of continuous monitoring by transmissometer which indicate that the opacity at the time visual observations were made was not in excess of the standard are probative but not conclusive evidence of the actual opacity of an emission, provided that the source shall meet the burden of proving that the instrument used meets (at the time of the alleged violation) Performance Specification I in Appendix B of this part, has been properly maintained and (at the time of the alleged violation) calibrated, and that the resulting data have not been tampered with in any way.

(c) The opacity standards set forth in this part shall apply at all times except during periods of start-up, shutdown, or malfunction, and as otherwise provided in the applicable standard.

(d) At all times, including periods of start-up, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.

(e)(1) An owner or operator of an affected facility may request the Administrator to determine opacity of emissions from the affected facility during the initial performance tests required by §60.8.

(2) Upon receipt from such owner or operator of the written report of the results of the performance tests required by §60.8, the Administrator will make a finding concerning compliance with opacity and other applicable standards. If the Administrator finds that an affected facility is in compliance with all applicable standards for which performance tests are conducted in accordance with §60.8 of this part but during the time such performance tests are being conducted fails to meet any applicable opacity standard, he shall notify the owner or operator and advise him that he may petition the Administrator within 10 days of receipt of notification to make appropriate adjustment to the opacity standard for the affected facility.

(3) The Administrator will grant such a petition upon a demonstration by the owner or operator that the affected facility and associated air pollution control equipment was operated and maintained in a manner to minimize the opacity of emissions during the performance tests; that the performance tests were performed under the conditions established by the Administrator; and that the affected facility and associated air pollution control equipment were incapable of being adjusted or operated to meet the applicable opacity standard.

(4) The Administrator will establish an opacity standard for the affected facility meeting the above requirements at a level at which the source will be able, as indicated by the performance and opacity tests, to meet the opacity standard at all times during which the source is meeting the mass or concentration emission standard. The Administrator will promulgate the new opacity standard in the Federal Register.

§60.12 Circumvention.

No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.

Subpart D - Standards of Performance for Fossil-Fuel-Fired Steam Generators

§60.40 Applicability and designation of affected facility.

The provisions of this subpart are applicable to each fossil-fuel-fired steam generating unit of more than 63 million kcal per hour heat input (250 million BTU per hour), which is the affected facility. Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring the unit under the applicablility of this subpart.

§60.41 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, and in subpart A of this part.

(a) "Fossil-fuel-fired steam generating unit" means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.

(b) "Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

§60.42 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which:

(1) Contain particulate matter in excess of 0.18 g per million cal heat input (0.10 lb per million BTU) derived from fossil fuel.

(2) Exhibit greater than 20 percent opacity except that a maximum of 40 percent opacity shall be permissible for not more than 2 minutes in any hour.

§60.43 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of:

(1) 1.4 g per million cal heat input (0.80 lb per million BTU) derived from liquid fossil fuel.

(2) 1.4 g per million cal heat input (1.2 lb per million BTU) derived from solid fossil fuel.

(b) When different fossil fuels are burned simultaneously in any combination, the applicable standard shall be determined by proration using the following formula:

$$\frac{y(1.4) + z(2.2)}{y + z}$$

where:

y is the percentage of total heat input derived from liquid fossil fuel, and

z is the percentage to total heat input derived from solid fossil fuel.

(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

§60.64 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required to be conducted by §60.8 is completed, no owner or operator subject to the provisions of this part shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2 in excess of:

(1) 0.36 g per million cal heat input (0.20 lb per million BTU) derived from gaseous fossil fuel,

(2) 0.54 g per million cal heat input (0.30 lb per million BTU) derived from liquid fossil fuel.

(3) 1.26 g per million cal heat input (0.70 lb per million BTU) derived from solid fossil fuel (except lignite),

(b) When different fossil fuels are burned simultaneously is any combination, the applicable standard shall be determined by proration. Compliance shall be determined by using the following formula:

$$\frac{x(0.36) + (0.54) + z(1.26)}{x + y + z}$$

where:

x is the percentage of total heat input derived from gaseous fossil fuel,
y is the percentage of total heat input derived from liquid fossil fuel, and
z is the percentage of total heat input derived from solid fossil fuel (except lignite).

§60.45 Emission and fuel monitoring.

(a) There shall be installed, calibrated, maintained, and operated, in any fossil-fuel-fired steam generating unit subject to the provisions of this part, emission monitoring instruments as follows:

(1) A photoelectric or other type smoke detector and recorder, except where gaseous fuel is the only fuel burned.

(2) An instrument for continuously monitoring and recording sulfur dioxide emissions, except where gaseous fuel is the only fuel burned, or where compliance is achieved through low sulfur fuels and representative sulfur analysis of fuels are conducted daily in accordance with paragraph (c) or (d) of this section.

(3) An instrument for continuously monitoring and recording emissions of nitrogen oxides.

(b) Instruments and sampling systems installed and used pursuant to this section shall be capable of monitoring emission levels within ±20 percent with a confidence level of 95 percent and shall be calibrated in accordance with the method(s) of such instruments; instruments shall be subject to manufacturers recommended zero adjustment and calibration procedures at least once per 24-hour operating period unless the manufacturer(s) specifies or recommends calibration at shorter intervals, in which case such specifications or recommendations shall be followed. The applicable method specified in the appendix of this part shall be the reference method.

(c) The sulfur content of solid fuels, as burned, shall be determined in accordance with the following methods of the American Society for Testing and Materials.

(1) Mechanical sampling by Method D 2234065.

(2) Sample preparation by Method D 2013-65.

(3) Sample analysis by Method D 271-68.

(d) The sulfur content of liquid fuels, as burned, shall be determined in accordance with the American Society for Testing and Materials D 1551-68, or D 129-64, or D 1552-64.

(e) The rate of fuel burned for each fuel shall be measured daily or at shorter intervals and recorded. The heating value and ash content of fuels shall be ascertained at least once per week and recorded. Where the steam generating unit is used to generate electricity, the average electrical output and the minimum and maximum hourly generation rate shall be measured and recorded daily.

(g) For the purpose of reports required pursuant to §60.7(a), periods of excess emissions that shall be reported are defined as follows:

(1) Opacity. All hourly periods during which there are three or more one-minute periods when the average opacity exceeds 20 percent.

(2) Sulfur dioxide. Any two consecutive hourly periods during which average sulfur dioxide emissions exceed 0.80 pound per million BTU heat input for solid fossil fuel burning equipment or exceed 1.2 pound per million BTU heat input for solid fossil fuel burning equipment; or for sources which elect to conduct representatives analyses of fuels in accordance with paragraph (c) or (d) of this section in lieu of installing and operating a monitoring device pursuant to paragraph (a)(2) of this section, any calendar day during which fuel analysis shows that the limits of §60.43 are exceeded.

(3) Nitrogen oxides. Any two consecutive hourly periods during which the average nitrogen oxides emissions exceed 0.20 pound per million BTU heat input for gaseous fossil fuel burning equipment, or exceed 0.30 pound per million BTU for liquid fossil fuel burning equipment, or exceed 0.70 pound per million BTU heat input for solid fossil fuel burning equipment.

§60.46 Test methods and procedures.

(a) The reference methods in Appendix A to this part, except as provided for in §60.8(b), shall be used to determine compliance with the standards prescribed in §§60.42, 60.43, and 60.44 as follows:

(1) Method 1 for sample and velocity traverses;

(2) Method 2 for velocity and volumetric flow rate;

(3) Method 3 for gas analysis;

(4) Method 5 for the concentration of particulate matter and the associated moisture content;

(5) Method 6 for the concentration of SO_2; and

(6) Method 7 for the concentration of NO_x.

(b) For Method 5, the sampling time for each run shall be at least 60 minutes and the minimum sample volume shall be 0.85 dscm (30.0 dscf) except that smaller sampling times or sample volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(c) For Methods 6 and 7, the sampling site shall be the same as that for determining volumetric flow rate. The sampling point in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft).

(d) For Method 6, the minimum sampling time shall be 20 minutes and the minimum sample volume shall be 0.02 dscm (0.71 dscf) except that smaller sampling times and sample volumes, when necessitated by process variables or other factors, may be approved by the Administrator. The sample shall be extracted at a rate proportional to the gas velocity at the sampling point. The arithmetic average of two samples shall constitute one run. Samples shall be taken at approximately 30-minute intervals.

(e) For Method 7, each run shall consist of at least four grab samples taken at approximately 15-minute intervals. The arithmetic mean of the samples shall constitute the run values.

(f) Heat input, expressed in cal per hr (BTU/hr), shall be determined during each test period by multiplying the heating value of the fuel by the rate of fuel burned. Heating value shall be determined in accordance with ASTM Method D2015-66 (Reapproved 1972), D240-64 (Reapproved 1973), or D1826-64 (Reapproved 1970). The rate of fuel burned during each testing period shall be determined by suitable methods, and shall be confirmed by a material balance over the steam generation system.

(g) For each run, emissions expressed in g/million cal shall be determined by dividing the emission rate in g/hr by the heat input. The emission rate shall be determined by the equation g/hr = Q_s x c where Q_s = volumetric flow rate of the total effluent in dscm/hr as determined for each run in accordance with paragraph (a)(2) of this section.

(1) For particulate matter, c = particulate concentration in g/dscm, as determined in accordance with paragraph (a)(4) of this section.

(2) For SO_2, c = SO_2 concentration in g/dscm, as determined in accordance with paragraph (a)(5) of this section.

(3) For NO_x, c = NO_x concentration in g/dscm, as determined in accordance with paragraph (a)(6) of this section.

APPENDIX - TEST METHODS

Method 1 - Sample and Velocity Traverses For Stationary Sources

1. Principle and Applicability

1.1 Principle. A sampling site and the number of traverse points are selected to air in the extraction of a representative sample.

1.2 Applicability. This method should be applied only when specified by the test procedures for determining compliance with the New Source Performance Standards. Unless otherwise specified, this method is not intended to apply to gas streams other than those emitted directly to the atmosphere without further processing.

2. Procedure

2.1 Selection of a sampling site and minimum number of traverse points.

2.1.1 Select a sampling site that is at least eight stack or duct diameters downstream and two diameters upstream from any flow disturbance such as a bend, expansion, contraction, or visible flame. For rectangular cross section, determine an equivalent diameter from the following equation:

$$\text{equivalent diameter} = 2\left(\frac{(\text{length})(\text{width})}{\text{length} + \text{width}}\right) \qquad \text{equation 1-1}$$

2.1.2 When the above sampling site criteria can be met, the minimum number of traverse points is twelve (12).

2.1.3 Some sampling situations render the above sampling site criteria impractical. When this is the case, choose a convenient sampling location and use Figure 1-1 to determine the minimum number of traverse points. Under no conditions should a sampling point be selected within 1 inch of the stack wall. To obtain the number of traverse points for stacks or ducts with a diameter less than 2 feet, multiply the number of points obtained from Figure 1-1 by 0.67.

2.1.4 To use Figure 1-1 first measure the distance from the chosen sampling location to the nearest upstream and downstream disturbances. Determine the corresponding number of traverse points for each distance from Figure 1-1.

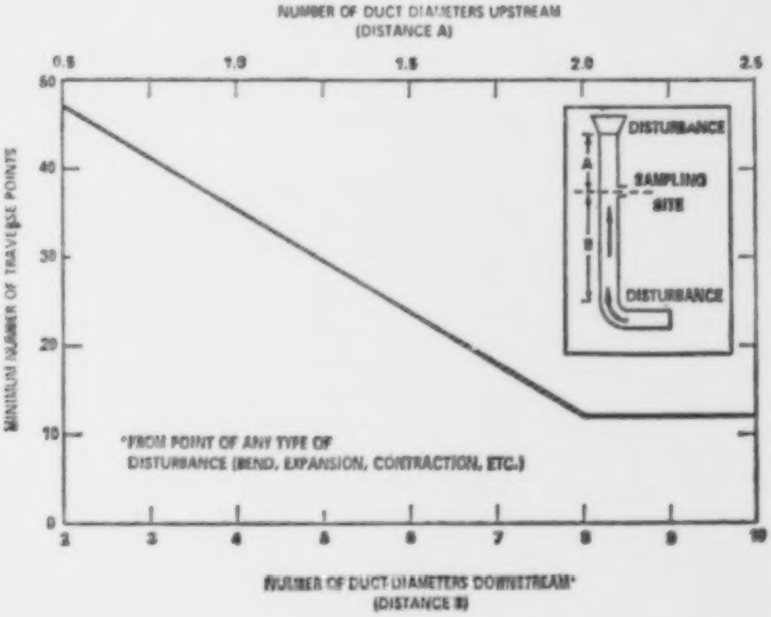


Figure 1-1. Minimum number of traverse points.

Select the higher of the two numbers of traverse points, or a greater value, such that for circular stacks the number is a multiple of 4, and for rectangular stacks the number follows the criteria of section 2.2.2.

2.2 Cross-sectional layout and location of traverse points.

2.2.1 For circular stacks locate the traverse points on at least two diameters according to Figure 1-2 and Table 1-1. The traverse axes shall divide the stack cross section into equal parts.

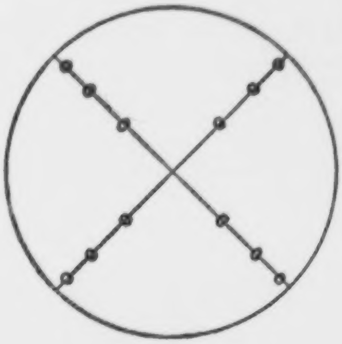


Figure 1-2. Cross section of circular stack divided into 12 equal areas, showing location of traverse points at centroid of each area.

Table 1-1. Location of traverse points in circular stacks
(Percent of stack diameter from inside wall to traverse point)

Traverse point number on a diameter	Number of traverse points on a diameter											
	2	4	6	8	10	12	14	16	18	20	22	24
1	14.6	6.7	4.4	3.3	2.5	2.1	1.8	1.6	1.4	1.3	1.1	1.1
2	85.4	25.0	14.7	10.5	8.2	6.7	5.7	4.9	4.4	3.9	3.5	3.2
3		75.0	29.5	19.4	14.6	11.8	9.9	8.5	7.5	6.7	6.0	5.5
4		93.3	70.5	32.3	22.6	17.7	14.6	12.5	10.9	9.7	8.7	7.9
5			85.3	67.7	34.2	25.0	20.1	16.9	14.6	12.9	11.6	10.5
6			95.6	80.6	65.8	35.5	26.9	22.0	18.8	16.5	14.6	13.2
7				89.5	77.4	64.5	36.6	28.3	23.6	20.4	18.0	16.1
8				96.7	85.4	65.0	63.4	37.5	29.6	25.0	21.8	19.4
9					91.8	82.3	73.1	62.5	38.2	30.6	26.1	23.0
10					97.5	88.2	79.3	71.7	61.8	38.8	31.5	27.2
11						93.3	85.4	78.0	70.4	61.2	39.3	32.3
12						97.9	90.1	83.1	76.4	69.4	60.7	39.8
13							94.3	87.5	81.2	75.0	68.5	60.2
14							98.2	91.5	85.4	79.6	73.9	67.7
15								95.1	89.1	83.5	78.2	72.8
16								98.4	92.5	87.1	82.0	77.0
17									95.6	90.3	85.4	80.6
18									98.6	93.3	88.4	83.9
19										96.1	91.3	86.8
20										98.7	94.0	89.5
21											96.5	92.1
22											98.9	94.5
23												96.8
24												98.9

2.2.2 For rectangular stacks divide the cross section into as many equal rectangular areas as traverse points, such that the ratio of the length to the width of the elemental areas is between one and two. Locate the traverse points at the centroid of each equal area according to Figure 1-3.

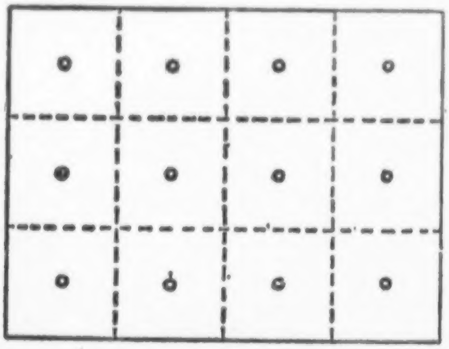


Figure 1-3. Cross section of rectangular stack divided into 12 equal areas, with traverse points at centroid of each area.

3. References

Determining Dust Concentration in a Gas Stream, ASME Performance Test Code #27, New York, N.Y., 1957.

Devorkin, Howard, et al., Air Pollution Source Testing Manual, Air Pollution Control District, Los Angeles, California, November 1963.

Methods for Determination of Velocity, Volume, Dust and Mist Content of Gases, Western Precipitation Division of Joy Manufacturing Co., Los Angeles, California, Bulletin WP-50, 1968.

Standard Method for Sampling Stacks for Particulate Matter, In: 1971 Book of ASTM Standards, Part 23, Philadelphia, Pennsylvania, 1971, ASTM Designation D-2928-71.

Method 2 - Determination of Stack Gas Velocity and Volumetric Flow Rate (Type S Pitot Tube)

1. Principle and applicability

1.1 Principle. Stack gas velocity is determined from the gas density and from measurement of the velocity head using a Type S (Stauscheibe or reverse type) pitot tube.

1.2 Applicability. This method should be applied only when specified by the test procedures for determining compliance with the New Source Performance Standards.

2. Apparatus

2.1 Pitot tube - Type S (Figure 2-1), or equivalent, with a coefficient within ±5% over the working range.

2.2 Differential pressure gauge - Inclined manometer, or equivalent, to measure velocity head to within 10% of the minimum value.

2.3 Temperature gauge - Thermocouple or equivalent attached to the pitot tube to measure stack temperature to within 1.5% of the minimum absolute stack temperature.

2.4 Pressure gauge - Mercury-filled U-tube manometer, or equivalent, to measure stack pressure to within 0.1 in. Hg.

2.5 Barometer - To measure atmospheric pressure to within 0.1 in. Hg.

2.6 Gas analyzer - To analyze gas composition for determining molecular weight.

2.7 Pitot tube - Standard type, to calibrate Type S pitot tube.

3. Procedure

3.1 Set up the apparatus as shown in Figure 2-1. Make sure all connections are tight and leak free. Measure the velocity head and temperature at the traverse points specified by Method 1.

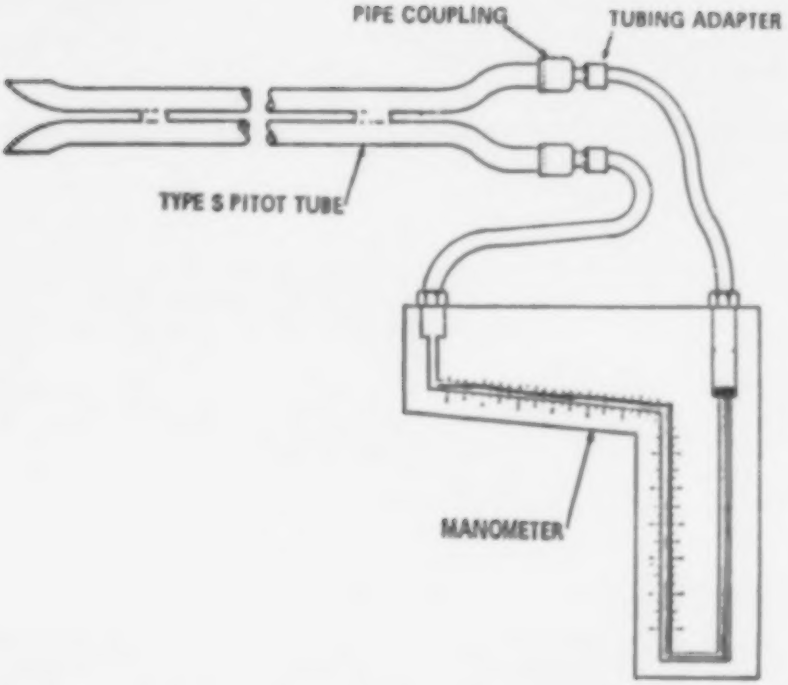


Figure 2-1. Pitot tube-manometer assembly.

3.2 Measure the static pressure in the stack.

3.3 Determine the stack gas molecular weight by gas analysis and appropriate calculations as indicated in Method 3.

4. Calibration

4.1 To calibrate the pitot tube, measure the velocity heat at some point in a flowing gas stream with both a Type S pitot tube and a standard type pitot tube with known coefficient. Calibration should be done in the laboratory and the velocity of the flowing gas stream should be varied over the normal working range. It is recommended that the calibration be repeated after use at each field site.

4.2 Calculate the pitot tube coefficient using equation 2-1.

$$C_{p_{test}} = C_{p_{std}} \sqrt{\frac{\Delta P_{std}}{\Delta P_{test}}} \qquad \text{equation 2-1}$$

where:

$C_{p_{test}}$ = Pitot tube coefficient of Type S pitot tube.

$C_{p_{std}}$ = Pitot tube coefficient of standard type pitot tube (if unknown, use 0.99)

$\Delta_{p_{std}}$ = Velocity head measured by standard type pitot tube.

$\Delta_{p_{test}}$ = Velocity head measured by Type S pitot tube.

4.3 Compare the coefficients of the Type S pitot tube determined first with one leg and then the other pointed downstream. Use the pitot tube only if the two coefficients differ by no more than 0.01.

5. Calculations

Use equation 2-2 to calculate the stack gas velocity.

$$(V_s)_{avg.} = K_p C_p (\sqrt{\Delta p})_{avg.} \sqrt{\frac{(T_s)_{avg.}}{P_s M_s}} \qquad \text{equation 2-2}$$

where:

$(V_s)_{avg.}$ = Stack gas velocity, feet per second (f.p.s.)

$K_p = 85.48 \frac{ft.}{sec.} \left(\frac{lb.}{lb.mole-°R}\right)^{1/2}$ when these units are used.

C_p = Pitot tube coefficient, dimensionless.

$(T_s)_{avg.}$ = Average absolute stack gas temperature, °R.

$(\sqrt{\Delta p})_{avg.}$ = Average velocity head of stack gas, inches H_2O (see Figure 2-2).

P_s = Absolute velocity head of stack gas (wet basis), lb/lb-mole.

M_s = Molecular weight of stack gas (wet basis), lb./lb.-mole $M_d(1-B_{wo})+18B_{wo}$

M_d = Dry molecular weight of stack gas (from Method 3).

B_{wo} = Proportion by volume of water vapor in the gas stream (from Method 4).

Figure 2-2 shows a sample recording sheet for velocity traverse data. Use the averages in the last two columns of Figure 2-2 to determine the average stack gas velocity from Equation 2-2.

PLANT ______

DATE ______

RUN NO ______

STACK DIAMETER, in ______

BAROMETRIC PRESSURE, in. Hg ______

STATIC PRESSURE IN STACK (P_g), in. Hg. ______

OPERATORS ______

SCHEMATIC OF STACK CROSS SECTION

Traverse point number	Velocity head, in. H_2O	$\sqrt{\Delta p}$	Stack Temperature (T_s), °F
	AVERAGE:		

Figure 2-2. Velocity traverse data.

Use Equation 2-3 to calculate the stack gas volumetric flow rate.

$$Q_s = 3600\,(1 - B_{wo})\,V_s A \left(\frac{T_{std}}{(T_s)_{avg.}}\right)\left(\frac{P_s}{P_{std}}\right) \qquad \text{equation 2-3}$$

where:

Q_s = Volumetric flow rate, dry basis, standard conditions, ft.^{3}/hr.

A = Cross-sectional area of stack, ft^2

T_{std} = Absolute temperature at standard conditions, 530°R.

P_{std} = Absolute pressure at standard conditions, 29.92 inches Hg.

6. References

Mark, L. S., Mechanical Engineers' Handbook, McGraw-Hill Book Co., Inc., New York, N.Y., 1951.

Perry, J. H., Chemical Engineers' Handbook, McGraw-Hill Book Co., Inc., New York, N.Y., 1960.

Shigehara, R. T., W. F. Todd, and W. S. Smith, Significance of Errors in Stack Sampling Measurements. Paper presented at the Annual Meeting of the Air Pollution Control Association, St. Louis, Missouri, June 14-19, 1970.

Standard Method for Sampling Stacks for Particulate Matter, In: 1971 Book of ASTM Standards, Part 23, Philadelphia, Pennsylvania, 1971, ASTM Designation D-2928-71.

Vennard J. D., Elementary Fluid Mechanics, John Wiley & Sons, Inc., New York, N.Y., 1947.

Method 3 - Gas Anaylsis for Carbon Dioxide, Excess Air, and Dry Molecular Weight

1. Principle and applicability

1.1 Principle. An integrated or grab gas sample is extracted from a sampling point and analyzed for its components using an Orsat analyzer.

1.2 Applicability. This method should be applied only when specified by the test procedures for determining compliance with the New Source Performance Standards. The test procedure will indicate whether a grab sample or an integrated sample is to be used.

2. Apparatus

2.1 Grab sample (Figure 3-1).

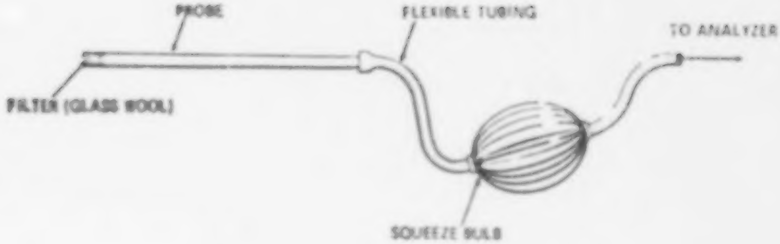

PROBE
FLEXIBLE TUBING
TO ANALYZER
FILTER (GLASS WOOL)
SQUEEZE BULB

Figure 3-1. Grab-sampling train.

2.1.1 Probe - Stainless steel or Pyrex[1] glass, equipped with a filter to remove particulate matter.

2.1.2 Pump - One-way squeeze bulb, or equivalent, to transport gas sample to analyzer.

2.2 Integrated sample (Figure 3-2).

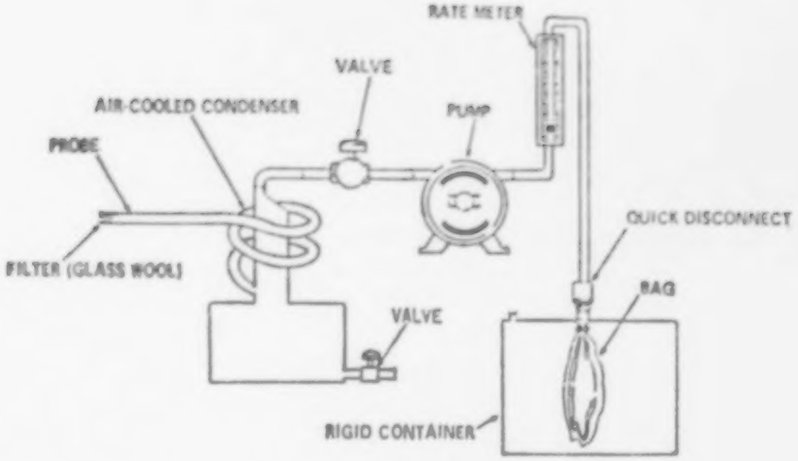

RATE METER
VALVE
AIR-COOLED CONDENSER
PUMP
PROBE
QUICK DISCONNECT
FILTER (GLASS WOOL)
BAG
VALVE
RIGID CONTAINER

Figure 3-2. Integrated gas - sampling train.

2.2.1 Probe - Stainless steel or Pyrex[1] glass, equipped with a filter to remove particulate matter.

2.2.2 Air-cooled condenser or equivalent - To remove any excess moisture.

2.2.3 Needle valve - To adjust flow rate.

2.2.4 Pump - Leak-free, diaphragm type, or equivalent, to pull gas.

2.2.5 Rate meter - To measure a flow range from 0 to 0.035 cfm.

---

[1] Trade name.

2.2.6 Flexible bag - Tedlar,[1] or equivalent, with a capacity of 2 to 3 cu. ft. Leak test the bag in the laboratory before using.

2.2.7 Pitot tube - Type S, or equivalent, attached to the probe so that the sampling flow rate can be regulated proportional to the stack gas velocity when velocity is varying with time or a sample traverse is conducted.

2.3 Analysis

2.3.1 Orsat analyzer, or equivalent.

3. Procedure

3.1 Grab sampling

3.1.1 Set up the equipment as shown in Figure 3-1, making sure all connections are leak-free. Place the probe in the stack at a sampling point and purge the sampling line.

3.1.2 Draw sample into the analyzer.

3.2 Integrated Sampling

3.2.1 Evacuate the flexible bag. Set up the equipment as shown in Figure 3-2 with the bag disconnected. Place the probe in the stack and purge the sampling line. Connect the bag, making sure that all connections are tight and that there are no leaks.

3.2.2 Sample at a rate proportional to the stack velocity.

3.3 Analysis

3.3.1 Determine the CO_2, O_2, and CO concentrations as soon as possible. Make as many passes as are necessary to give constant readings. If more than ten passes are necessary, replace the absorbing solution.

3.3.2 For grab sampling, repeat the sampling and analysis until three consecutive samples vary no more than 0.5 percent by volume for each component being analyzed.

3.3.3 For integrated sampling, repeat the analyses of the sample until three consecutive analyses vary no more than 0.2 percent by volume for each component being analyzed.

4. Calculations

4.1 Carbon dioxide. Average the three consecutive runs and report the results to the nearest 0.1% CO_2.

4.2 Excess air. Use Equation 3-1 to calculate excess air, and average the runs. Report the result to the nearest 0.1% excess air.

$$\%EA = \frac{(\%O_2) - 0.5(\%CO)}{0.264(\%N_2) - (\%O_2) + 0.5(\%CO)} \times 100 \qquad \text{equation 3-I}$$

---

[1] Trade name.

where:

%EA = Percent excess air.

$\%O_2$ = Percent oxygen by volume, dry basis.

$\%N_2$ = Percent nitrogen by volume, dry basis.

%CO = Percent carbon monoxide by volume, dry basis.

0.264 = Ratio of oxygen to nitrogen in air by volume.

4.3 Dry molecular weight. Use Equation 3-2 to calculate dry molecular weight and average the runs. Report the result to the nearest tenth.

$$M_d = 0.44(\%CO_2) + 0.32(\%O_2) + 0.28(\%N_2 + \%\,CO) \qquad \text{equation 3-2}$$

where:

M_d = Dry molecular weight, lb./lb-mole.

$\%CO_2$ = Percent carbon dioxide by volume, dry basis.

$\%O_2$ = Percent oxygen by volume, dry basis.

$\%N_2$ = Percent nitrogen by volume, dry basis.

0.44 = Molecular weight of carbon dioxide divided by 100.

0.32 = Molecular weight of oxygen divided by 100.

0.28 = Molecular weight of nitrogen and CO divided by 100.

5. References

Altshuller, A. P., et al., Storage of Gases and Vapors in Plastic Bags, Int. J. Air & Water Pollution, 6:75-81, 1963.

Conner, William D., and J. S. Nader, Air Sampling with Plastic Bags, Journal of the American Industrial Hygiene Association, 25:291-297, May-June 1964.

Devorkin, Howard, et al., Air Pollution Source Testing Manual, Air Pollution Control District, Los Angeles, California, November 1963.

Method 4 - Determination of Moisture in Stack Gases

1. Principle and applicability

1.1 Principle. Moisture is removed from the gas stream, condensed, and determined volumetrically.

1.2 Applicability. This method is applicable for the determination of moisture in stack gas only when specified by test procedures for determining compliance with New Source Performance Standards. This method does not apply when liquid droplets are present in the gas stream[1] and the moisture is subsequently used in the determination of stack gas molecular weight.

Other methods such as drying tubes, wet bulb-dry bulb techniques, and volumetric condensation techniques may be used.

2. Apparatus

2.1 Probe - Stainless steel or Pyrex[2] glass sufficiently heated to prevent condensation and equipped with a filter to remove particulate matter.

2.2 Impingers - Two midget impingers, each with 30 ml. capacity, or equivalent.

2.3 Ice bath container - To condense moisture in impingers.

2.4 Silica gel tube (optional) - To protect pump and dry gas meter.

2.5 Needle valve - To regulate gas flow rate.

2.6 Pump - Leak-free, diaphragm type, or equivalent, to pull gas through train.

2.7 Dry gas meter - To measure to within 1% of the total sample volume.

2.8 Rotameter - To measure a flow range from 0 to 0.1 c.f.m.

2.9 Graduated cylinder - 25 ml.

2.10 Barometer - Sufficient to read to within 0.1 inch Hg.

2.11 Pitot tube - Type S, or equivalent, attached to probe so that the sampling flow rate can be regulated proportional to the stack gas velocity when velocity is varying with time or a sample traverse is conducted.

---

[1] If liquid droplets are present in the gas stream, assume the stream to be saturated, determine the average stack gas temperature by traversing according to Method 1, and use a psychrometric chart to obtain an approximation of the moisture percentage.

[2] Trade name.

3. Procedure

3.1 Place *exactly* 5 ml. distilled water in each impinger. Assemble the apparatus without the probe as shown in Figure 4-1. Leak check by plugging the inlet to the first impinger and drawing a vacuum. Insure that flow through the dry gas meter is less than 1% of the sampling rate.

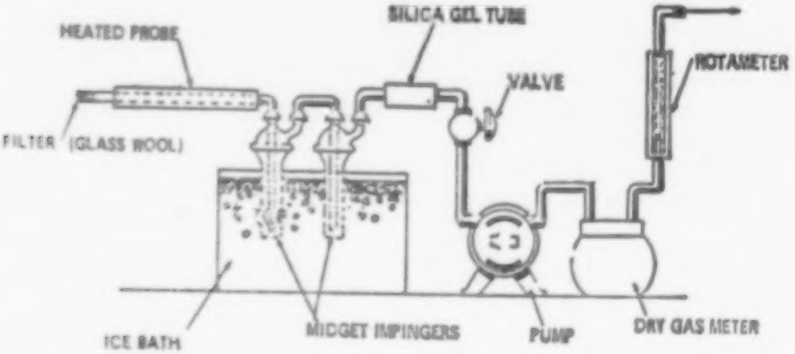

HEATED PROBE
SILICA GEL TUBE
VALVE
ROTAMETER
FILTER (GLASS WOOL)
ICE BATH
MIDGET IMPINGERS
PUMP
DRY GAS METER

Figure 4-1. Moisture-sampling train.

3.2 Connect the probe and sample at a constant rate of 0.075 c.f.m. or at a rate proportional to the stack gas velocity. Continue sampling until the dry gas meter registers 1 cubic foot or until visible liquid droplets are carried over from the first impinger to the second. Record temperature, pressure, and dry gas meter readings as required by Figure 4-2.

LOCATION____________________ COMMENTS
TEST____________________
DATE____________________
OPERATOR____________________

BAROMETRIC PRESSURE____________________

CLOCK TIME	GAS VOLUME THROUGH METER, (Vm), ft³	ROTAMETER SETTING ft³/min	METER TEMPERATURE, °F

Figure 4-2. Field moisture determination.

3.3 After collecting the sample, measure the volume increase to the nearest 0.5 ml.

4. Calculations

4.1 Volume of water vapor collected.

$$V_{wc} = \frac{(V_f - V_i)p_{H_2O} RT_{std}}{P_{std} M_{H_2O}} = 0.0474 \frac{ft.^3}{ml.} (V_f - V_i) \qquad \text{equation 4-1}$$

where:

V_{wc} = Volume of water vapor collected (standard) conditions), cu.ft.

V_f = Final volume of impinger contents, ml.

V_i = Initial volume of impinger contents, ml.

R = Ideal gas constant, 21.83 inches Hg - cu.ft./lb.mole-°R.

P_{H_2O} = Density of water, 1 g./ml.

T_{std} = Absolute temperature at standard conditions, 530°R.

P_{std} = Absolute pressure at standard conditions, 29.92 inches Hg.

M_{H_2O} = Molecular weight of water, 18 lb./lb.-mole.

4.2 Gas volume.

$$V_{mc} = V_m \left(\frac{P_m}{P_{std}}\right) \left(\frac{T_{std}}{T_m}\right) = 17.71 \frac{°R}{in.\ Hg} \left(\frac{V_m P_m}{T_m}\right) \qquad \text{equation 4-2}$$

where:

V_{mc} = Dry gas volume through meter at standard conditions, cu.ft.

V_m = Dry gas volume measured by meter, cu.ft.

P_m = Barometric pressure at the dry gas meter, inches Hg.

P_{std} = Pressure at standard conditions, 29.92 inches Hg.

T_{std} = Absolute temperature at standard conditions, 530°R.

T_m = Absolute temperature at meter (°F+460), °R.

4.3 Moisture content.

$$B_{wo} = \frac{V_{wc}}{V_{wc} + V_{mc}} + B_{wm} = \frac{V_{wc}}{V_{wc} + V_{mc}} + (0.025) \qquad \text{equation 4-3}$$

where:

B_{wo} = Proportion by volume of water vapor in the gas stream, dimensionless.

V_{wc} = Volume of water vapor collected (standard conditions), cu.ft.

V_{mc} = Dry gas volume through meter (standard conditions), cu.ft.

B_{wm} = Approximate volumetric proportion of water vapor in the gas stream leaving the impingers, 0.025.

5. References

Air Pollution Engineering Manual, Danielson, J. A. (ed.), U.S. DHEW, PHS, National Center for Air Pollution Control, Cincinnati, Ohio, PHS Publication No. 999-AP-40, 1967.

Devorkin, Howard, et al., Air Pollution Source Testing Manual, Air Pollution Control District, Los Angeles, California, November 1963.

Methods for Determination of Velocity, Volume, Dust and Mist Content of Gases, Western Precipitation Division of Joy Manufacturing Co., Los Angeles, California, Bulletin WP-50, 1968.

Method 5 - Determination of Particulate Emissions From Stationary Sources

1. Principle and applicability

1.1 Principle. Particulate matter is withdrawn isokinetically from the source and its weight is determined gravimetrically after removal of uncombined water.

1.2 Applicability. This method is applicable for the determination of particulate emissions from stationary sources only when specified by the test procedures for determining compliance with New Source Performance Standards.

2. Apparatus

2.1 Sampling train. The design specifications of the particulate sampling train used by EPA (Figure 5-1) are described in APTD-0581. Commercial models of this train are available.

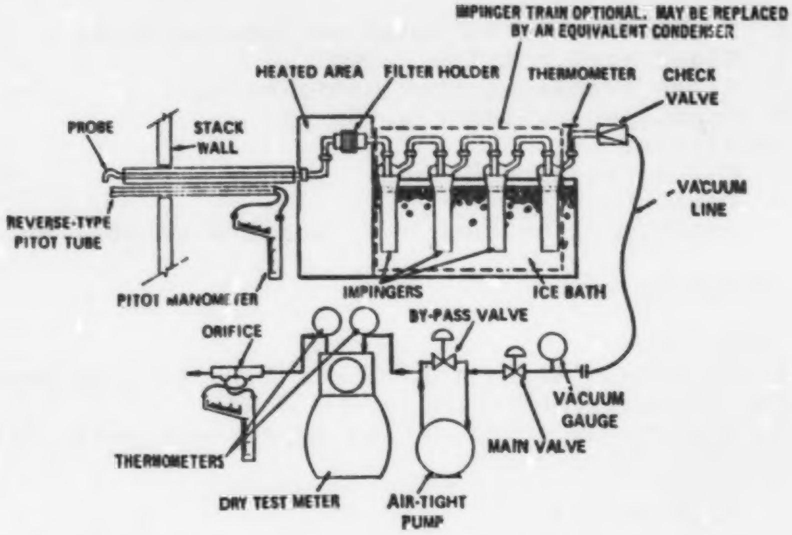

IMPINGER TRAIN OPTIONAL, MAY BE REPLACED BY AN EQUIVALENT CONDENSER
HEATED AREA
FILTER HOLDER
THERMOMETER
CHECK VALVE
PROBE
STACK WALL
VACUUM LINE
REVERSE-TYPE PITOT TUBE
PITOT MANOMETER
IMPINGERS
ICE BATH
ORIFICE
BY-PASS VALVE
VACUUM GAUGE
MAIN VALVE
THERMOMETERS
DRY TEST METER
AIR-TIGHT PUMP

Figure 5-1. Particulate-sampling train.

2.1.1 Nozzle - Stainless steel (316) with sharp, tapered leading edge.

2.1.2 Probe - Pyrex[1] glass with a heating system capable of maintaining a minimum gas temperature of 250°F at the exit end during sampling to prevent condensation from occurring. When length limitations (greater than about 8 ft.) are encountered at temperatures less than 600°F, Incoloy 825[1], or equivalent, may be used. Probes for sampling gas streams at temperatures in excess of 600°F must have been approved by the Administrator.

2.1.3 Pitot tube - Type S, or equivalent, attached to probe to monitor stack gas velocity.

2.1.4 Filter holder - Pyrex[1] glass with heating system capable of maintaining minimum temperature of 225°F.

2.1.5 Impingers/Condenser - Four impingers connected in series with glass ball joint fittings. The first, third, and fourth impingers are of the Greenburg-Smith design, modified by replacing the tip with a 1/2-inch ID glass tube extending to one-half inch from the bottom of the flask. The second impinger is of the Greenburg-Smith design with the standard tip. A condenser may be used in place of the impingers provided that the moisture content of the stack gas can still be determined.

2.1.6 Metering system - Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 5°F, dry gas meter with 2% accuracy, and related equipment, or equivalent, as required to maintain an isokinetic sampling rate and to determine sample volume.

2.1.7 Barometer - To measure atmospheric pressure to ±0.1 inches Hg.

---

[1] Trade name.

2.2 Sample recovery.
2.2.1 Probe brush - At least as long as probe.
2.2.2 Glass wash bottles - Two.
2.2.3 Glass sample storage containers.
2.2.4 Graduated cylinder - 250 ml.
2.3 Analysis.
2.3.1 Glass weighing dishes.
2.3.2 Desiccator.
2.3.3 Analytical balance - To measure to ±0.1 mg.

3. Reagents

3.1 Sampling
3.1.1 Filters - Glass fiber, MSA 1106 BH[1], or equivalent, numbered for identification and preweighed.
3.1.2 Silica gel - Indicating type, 6-16 mesh, dried at 175°C (350°F) for 2 hours.
3.1.3 Water.
3.1.4 Crushed ice.
3.2 Sample recovery.
3.2.1 Acetone - Reagent grade.
3.3 Analysis
3.3.1 Water.
3.3.2 Desiccant - Drierite,[1] indicating.

4. Procedure

4.1 Sampling
4.1.1 After selecting the sampling site and the minimum number of sampling points, determine the stack pressure, temperature, moisture, and range of velocity head.

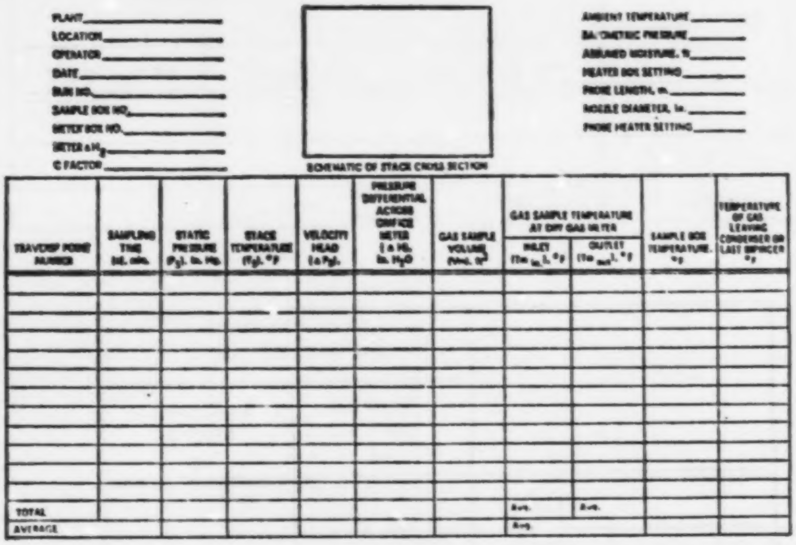
4.1.2 Preparation of collection train. Weigh to the nearest gram approximately 200 g. of silica gel. Label a filter of proper diameter, desiccate[2] for at least 24 hours and weigh to the nearest 0.5 mg. in a room where the relative humidity is less than 50%. Place 100 ml. of water in each of the first two impingers, leave the third impinger empty, and place approximately 200 g. of preweighed silica gel in the fourth impinger. Set up the train without the probe as in Figure 5-1. Leak check the sampling train at the sampling site by plugging up the inlet to the filter holder and pulling a 15 in. Hg vacuum. A leakage rate not in excess of 0.02 c.f.m. at a vacuum of 15 in. Hg is acceptable. Attach the probe and adjust the heater to provide a gas temperature of about 250°F at the probe outlet. Turn on the filter heating system. Place crushed ice around the impingers. Add more ice during the run to keep the temperature of the gases leaving the last impinger as low as possible and preferably at 70°F or less. Temperatures above 70°F may result in damage to the dry gas meter from either moisture condensation or excessive heat.

---

[1] Trade name.

[2] Dry using Drierite[1] at 70°F ±10°F.

4.1.3 Particulate train operation. For each run, record the data required on the example sheet shown in Figure 5-2. Take readings at each sampling point, at least every 5 minutes, and when significant changes in stack conditions necessitate additional adjustments in flow rate. To begin sampling, position the nozzle at the first traverse point with the tip pointing directly into the gas stream. Immediately start the pump and adjust the flow to isokinetic conditions. Sample for at least 5 minutes at each traverse point; sampling time must be the same for each point. Maintain isokinetic sampling throughout the sampling period. Nomographs are available which aid in the rapid adjustment of the sampling rate without other computations. APTD-0576 details the procedure for using these nomographs. Turn off the pump at the conclusion of each run and record the final readings. Remove the probe and nozzle from the stack and handle in accordance with the sampling recovery process described in section 4.2.



PLANT__________
LOCATION__________
OPERATOR__________
DATE__________
RUN NO.__________
SAMPLE BOX NO.__________
METER BOX NO.__________
METER $\Delta H_@$__________
C FACTOR__________

SCHEMATIC OF STACK CROSS SECTION

AMBIENT TEMPERATURE__________
BAROMETRIC PRESSURE__________
ASSUMED MOISTURE, %__________
HEATER BOX SETTING__________
PROBE LENGTH, m.__________
NOZZLE DIAMETER, in.__________
PROBE HEATER SETTING__________

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	STATIC PRESSURE (P_s), in. Hg	STACK TEMPERATURE (T_s), °F	VELOCITY HEAD (ΔP_s)	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER (ΔH), in. H_2O	GAS SAMPLE VOLUME (V_m), ft^3	GAS SAMPLE TEMPERATURE AT DRY GAS METER		SAMPLE BOX TEMPERATURE, °F	TEMPERATURE OF GAS LEAVING CONDENSER OR LAST IMPINGER, °F
							INLET ($T_{m_{in}}$), °F	OUTLET ($T_{m_{out}}$), °F		
TOTAL							Avg.	Avg.		
AVERAGE							Avg.			

Figure 5-2. Particulate field data.

4.2 Sample recovery. Exercise care in moving the collection train from the test site to the sample recovery area to minimize the loss of collected sample or the gain of extraneous particulate matter. Set aside a portion of the acetone used in the sample recovery as a blank for analysis. Measure the volume of water from the first three impingers, then discard. Place the samples in containers as follows:

Container No. 1. Remove the filter from its holder, place in this container, and seal.

Container No. 2. Place loose particulate matter and acetone washings from all sample-exposed surfaces prior to the filter in this container and seal. Use a razor blade, brush, or rubber policeman to lose adhering particles.

Container No. 3. Transfer the silica gel from the fourth impinger to the original container and seal. Use a rubber policeman as an aid in removing silica gel from the impinger.

4.3 Analysis. Record the data required on the example sheet shown in Figure 5-3. Handle each sample container as follows:

PLANT________________
DATE ________________
RUN NO.________________

CONTAINER NUMBER	WEIGHT OF PARTICULATE COLLECTED, mg		
	FINAL WEIGHT	TARE WEIGHT	WEIGHT GAIN
1			
2			
TOTAL			

	VOLUME OF LIQUID WATER COLLECTED	
	IMPINGER VOLUME, ml	SILICA GEL WEIGHT, g
FINAL		
INITIAL		
LIQUID COLLECTED		
TOTAL VOLUME COLLECTED		g* ml

CONVERT WEIGHT OF WATER TO VOLUME BY DIVIDING TOTAL WEIGHT INCREASE BY DENSITY OF WATER. (1 g. ml):

$$\frac{\text{INCREASE, g}}{(1\ \text{g/ml})} = \text{VOLUME WATER, ml}$$

Figure 5-3. Analytical data.

Container No. 1. Transfer the filter and any loose particulate matter from the sample container to a tared glass weighed dish, desiccate, and dry to a constant weight. Report results to the nearest 0.5 mg.

Container No. 2. Transfer the acetone washings to a tared beaker and evaporate to dryness at ambient temperature and pressure. Desiccate and dry to a constant weight. Report results to the nearest 0.5 mg.

Container No. 3. Weigh the spent silica gel and report to the nearest gram.

5. Calibration

Use methods and equipment which have been approved by the Administrator to calibrate the orifice meter, pitot tube, dry gas meter, and probe heater. Recalibrate after each test series.

6. Calculations

6.1 Average dry gas meter temperature and average orifice pressure drop. See data sheet (Figure 5-2).

6.2 Dry gas volume. Correct the sample volume measured by the dry gas meter to standard conditions (70°F, 29.92 inches Hg) by using Equation 5-1.

$$V_{m_{std}} = V_m \left(\frac{T_{std}}{T_m}\right)\left(\frac{P_{bar} + \frac{\Delta H}{13.6}}{P_{std}}\right) = \left(17.71 \frac{°R}{in.Hg}\right) V_m \left(\frac{P_{bar} + \frac{\Delta H}{13.6}}{T_m}\right) \qquad \text{equation 5-l}$$

where:

$V_{m_{std}}$ = Volume of gas sample through the dry gas meter (standard conditions), cu. ft.

V_m = Volume of gas sample through the dry gas meter (meter conditions), cu. ft.

T_{std} = Absolute temperature at standard conditions, 530°R.

T_m = Average dry gas meter temperature, °R.

P_{bar} = Barometric pressure at the orifice meter, inches Hg.

ΔH = Average pressure drop across the orifice meter, inches H_2O.

13.6 = Specific gravity of mercury.

P_{std} = Absolute pressure at standard conditions, 29.92 inches Hg.

6.3 Volume of water vapor.

$$V_{w_{std}} = V_{1_c} \left(\frac{\rho_{H_2O}}{M_{H_2O}}\right) \left(\frac{RT_{std}}{P_{std}}\right) = \left(0.0474 \frac{\text{cu. ft.}}{\text{ml.}}\right) V_{1_c} \qquad \text{equation 5-2}$$

where:

$V_{w_{std}}$ = Volume of water vapor in the gas sample (standard conditions), cu. ft.

V_{1_c} = Total volume of liquid collected in impingers and silica gel (see Figure 5-3), ml.

ρ_{H_2O} = Density of water, 1 g./ml.

M_{H_2O} = Molecular weight of water, 18 lb./lb.-mole.

R = Ideal gas constant, 21.83 inches Hg-cu. ft./lb.-mole-°R.

T_{std} = Absolute temperature at standard conditions, 530°R.

P_{std} = Absolute pressure at standard conditions, 29.92 inches Hg.

6.4 Moisture content.

$$B_{wo} = \frac{V_{w_{std}}}{V_{m_{std}} + V_{w_{std}}} \qquad \text{equation 5-3}$$

where:

B_{wo} = Proportion by volume of water vapor in the gas stream, dimensionless.

$V_{w_{std}}$ = Volume of water in the gas sample (standard conditions), cu. ft.

$V_{m_{std}}$ = Volume of gas sample through the dry gas meter (standard conditions), cu. ft.

6.5 Total particulate weight. Determine the total particulate catch from the sum of the weights on the analysis data sheet (Figure 5-3).

6.6 Concentration.

6.6.1 Concentration in gr./s.c.f.

$$c'_s = \left(0.0154 \frac{\text{gr.}}{\text{mg.}}\right) \left(\frac{M_n}{V_{m_{std}}}\right) \qquad \text{equation 5-4}$$

where:

c'_s = Concentration of particulate matter in stack gas, gr./s.c.f., dry basis.

M_n = Total amount of particulate matter collected, mg.

$V_{m_{std}}$ = Volume of gas sample through dry gas meter (standard conditions), cu. ft.

6.6.2 Concentration in lb./cu. ft.

$$c_s = \frac{\left(\frac{1}{453{,}600}\ \frac{\text{lb.}}{\text{mg.}}\right) M_n}{V_{m_{std}}} = 2.205 \times 10^{-6}\ \frac{M_n}{V_{m_{std}}} \qquad \text{equation 5-5}$$

where:

C_a = Concentration of particulate matter in stack gas, lb./s.c.f., dry basis.

453,600 = Mg/lb.

M_n = Total amount of particulate matter collected, mg.

$V_{m_{std}}$ = Volume of gas sample through dry gas meter (standard conditions), cu. ft.

6.7 Isokinetic variation.

$$I = \frac{T_s\left[\frac{V_{1_c}(\rho_{H_2O})\,R}{M_{H_2O}} + \frac{V_m}{T_m}\left(P_{bar} + \frac{\Delta H}{13.6}\right)\right]}{\Theta V_s P_s A_n} \times 100$$

$$= \frac{\left(1.667\ \frac{\text{min.}}{\text{sec.}}\right)\left[\left(0.00267\ \frac{\text{in. Hg-cu. ft.}}{\text{ml.-}^\circ\text{R}}\right)V_{1_c} + \frac{V_m}{T_m}\left(P_{bar} + \frac{\Delta H}{13.6}\right)\right]}{\Theta V_s P_s A_n} \qquad \text{equation 5-6}$$

where:

I = Percent of isokinetic sampling.

V_{1_c} = Total volume of liquid collected in impingers and silica gel (See Fig. 5-3), ml.

p_{H_2O} = Density of water, 1 g./ml.

R = Ideal gas constant, 21.83 inches Hg-cu. ft./lb. mole-°R.

M_{H_2O} = Molecular weight of water, 18 lb./lb.-mole.

V_m = Volume of gas sample through the gas meter (meter conditions), cu. ft.

T_m = Absolute average dry gas meter temperature (See Figure 5-2), °R.

P_{bar} = Barometric pressure at sampling site, inches Hg.

ΔH = Average pressure drop across the orifice (see Fig. 5-2), inches H_2O.

T_s = Absolute average stack gas temperature (see Fig. 5-2), °R.

Θ = Total sampling time, min.

V_s = Stack gas velocity calculated by Method 2, Equation 2.2, ft./sec.

P_s = Absolute stack gas pressure, inches Hg.

A_n = Cross-sectional area of nozzle, sq. ft.

6.8 Acceptable results. The following range sets the limit on acceptable isokinetic sampling results:

If $90\% \leq I < 110\%$, the results are acceptable, otherwise, reject the results and repeat the test.

7. Reference.

Addendum to Specifications for Incinerator Testing at Federal Facilities, PHS, NCAPC, Dec. 6, 1967.

Martin, Robert M., Construction Details of Isokinetic Source Sampling Equipment, Environmental Protection Agency, APTD-0581.

Rom, Jerome J., Maintenance, Calibration, and Operation of Isokinetic Source Sampling Equipment, Environmental Protection Agency, APTD-0576.

Smith, W. S., R.T. Shigehara, and W. F. Todd, A Method of Interpreting Stack Sampling Data, Paper presented at the 63rd Annual Meeting of the Air Pollution Control Association, St. Louis, Mo., June 14-19, 1970.

Smith, W. S., et.al., Stack Gas Sampling Improved and Simplified with New Equipment, APCA paper No. 67-119, 1967.

Specifications for Incinerator Testing at Federal Facilities, PHS, NCAPC, 1967.

Method 6 - Determination of Sulfur Dioxide Emissions from Stationary Sources

1. Principle and applicability

1.1 Principle. A gas sample is extracted from the sampling point in the stack. The acid mist, including sulfur trioxide, is separated from the sulfur dioxide. The sulfur dioxide fraction is measured by the barium-thorin titration method.

1.2 Applicability. This method is applicable for the determination of sulfur dioxide emissions from stationary sources only when specified by the test procedures for determining compliance with New Source Performance Standards.

2. Apparatus

2.1 Sampling. See Figure 6-1.

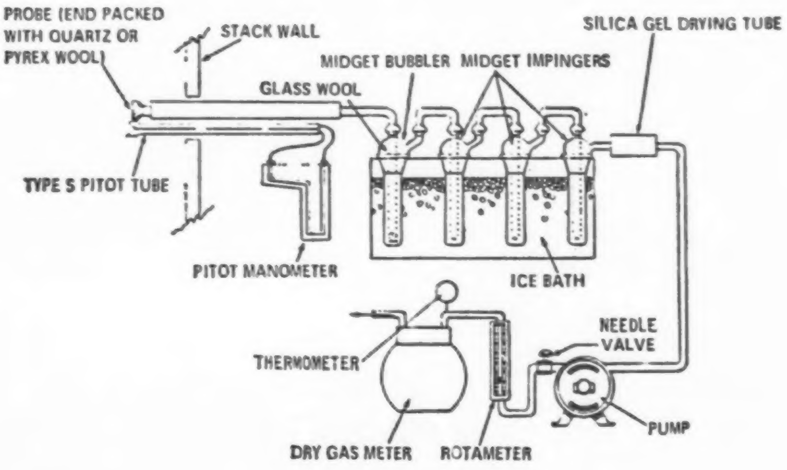

PROBE (END PACKED WITH QUARTZ OR PYREX WOOL)
STACK WALL
SILICA GEL DRYING TUBE
MIDGET BUBBLER
MIDGET IMPINGERS
GLASS WOOL
TYPE S PITOT TUBE
PITOT MANOMETER
ICE BATH
NEEDLE VALVE
THERMOMETER
PUMP
DRY GAS METER
ROTAMETER

Figure 6.1. SO_2 sampling train.

2.1.1 Probe - Pyrex[1] glass, approximately 5 to 6 mm, ID, with a heating system to prevent condensation and a filtering medium to remove particulate matter including sulfuric acid mist.

2.1.2 Midget bubbler - One, with glass wool packed in top to prevent sulfuric acid mist carryover.

2.1.3 Glass wool.

2.1.4 Midget impingers - Three.

2.1.5 Drying tube - Packed with 6 to 16 mesh indicating-type silica gel, or equivalent, to dry the sample.

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[1] Trade name.

2.1.6 Valve - Needle valve, or equivalent, to adjust flow rate.

2.1.7 Pump - Leak-free, vacuum type.

2.1.8 Rate meter - Rotameter or equivalent, to measure a 0-10 s.c.f.h. flow range.

2.1.9 Dry gas meter - Sufficiently accurate to measure the sample volume within 1%.

2.1.10 Pitot tube - Type S, or equivalent, necessary only if a sample traverse is required, or if stack gas velocity varies with time.

2.2 Sample recovery.

2.2.1 Glass wash bottles - Two.

2.2.2 Polyethylene storage bottles - To store impinger samples.

2.3 Analysis.

2.3.1 Pipettes - Transfer type, 5 ml. and 10 ml. sizes (0.1 ml. divisions) and 25 ml. size (0.2 ml. divisions).

2.3.2 Volumetric flasks - 50 ml., 100 ml., and 1,000 ml.

2.3.3 Burettes - 5 ml. and 50 ml.

2.3.4 Erlenmeyer flask - 125 ml.

3. Reagents

3.1 Sampling.

3.1.1 Water - Deionized, distilled.

3.1.2 Isopropanol, 80% - Mix 80 ml of isopropanol with 20 ml of distilled water.

3.1.3 Hydrogen peroxide, 3% - dilute 100 ml. of 30% hydrogen peroxide to 1 liter with distilled water. Prepare fresh daily.

3.2 Sample recovery.

3.2.1 Water - Deionized, distilled.

3.2.2 Isopropanol, 80%.

3.3 Analysis.

3.3.1 Water - Deionized, distilled.

3.3.2 Isopropanol.

3.3.3 Thorin indicator - 1-(o-arsonophenylazo)-2-naphthol-3, 6-disulfonic acid, disodium salt (or equivalent). Dissolve 0.20 g. in 100 ml. distilled water.

3.3.4 Barium perchlorate (0.01 N) - Dissolve 1.95 g. of barium perchlorate [$Ba(ClO_4)_2.3H_2O$] in 200 ml. distilled water and dilute to 1 liter with isopropanol. Standardize with sulfuric acid. Barium chloride may be used

3.3.5 Sulfuric acid standard (0.01 N) - Purchase or standardize to ±0.0002 N against 0.01N NaOH which has previously been standardized against potassium acid phthalate (primary standard grade).

4. Procedure

4.1 Sampling.

4.1.1 Preparation of collection train. Pour 15 ml. of 80% isopropanol into the midget bubbler and 15 ml. of 3% hydrogen peroxide into each of the first two midget impingers. Leave the final midget impinger dry. Assemble the train as shown in Figure 6-1. Leak check the sampling train at the sampling site by plugging the probe inlet and pulling a 10 inches Hg vacuum. A leakage rate not in excess of 1% of the sampling rate is acceptable. Carefully release the probe inlet plug and turn off the pump. Place crushed ice around the impingers. Add more ice during the run to keep the temperature of the gases leaving the last impinger at 70°F or less.

4.1.2 Sample collection. Adjust the sample flow rate proportional to the stack gas velocity. Take readings at least every five minutes and when significant changes in stack conditions necessitate additional adjustments in flow rate. To begin sampling, position the tip of the probe at the first sampling point and start the pump. Sample proportionally throughout the run. At the conclusion of each run, turn off the pump and record the final readings. Remove the probe from the stack and disconnect it from the train. Drain the ice bath and purge the remaining part of the train by drawing clean ambient air through the system for 15 minutes.

4.2 Sample recovery. Disconnect the impingers after purging. Discard the contents of the midget bubbler. Pour the contents of the midget impingers into a polyethylene shipment bottle. Rinse the three midget impingers and the connecting tubes with distilled water and add these washings to the same storage container.

4.3 Sample analysis. Transfer the contents of the storage container to a 50 ml. volumetric flask. Dilute to the mark with deionized, distilled water. Pipette a 10 ml. aliquot of this solution into a 125 ml. Erlenmeyer flask. Add 40 ml. of isopropanol and two to four drops of thorin indicator. Titate to a pink endpoint using 0.01 N barium perchlorate. Run a blank with each series of samples.

5. Calibration

5.1 Use standard methods and equipment which have been approved by the Administrator to calibrate the rotameter, pitot tube, dry gas meter, and probe heater.

5.2 Standardize the barium perchlorate against 25 ml. of standard sulfuric acid containing 100 ml. of isopropanol.

6. Calculations

6.1 Dry gas volume. Correct the sample volume measured by the dry gas meter to standard conditions (70°F and 29.92 inches Hg) by using equation 6-1.

$$V_{m_{std}} = V_m \left(\frac{T_{std}}{T_m}\right) \left(\frac{P_{bar}}{P_{std}}\right) = 17.71 \frac{°R}{in.\ Hg} \left(\frac{V_m P_{bar}}{T_m}\right) \qquad \text{equation 6-l}$$

where:

$V_{m_{std}}$ = Volume of gas sample through the dry gas meter (standard conditions), cu. ft.

V_m = Volume of gas sample through the dry gas meter (meter conditions), cu. ft.

T_{std} = Absolute temperature at standard conditions, 530°R.

T_m = Average dry gas meter temperature, °R.

P_{bar} = Barometric pressure at the orifice meter, inches Hg.

P_{std} = Absolute pressure at standard conditions, 29.92 inches Hg.

6.2 Sulfur dioxide concentration.

$$C_{SO_2} = \left(7.05 \times 10^{-5}\ \frac{lb.\text{-}l.}{g.\text{-}ml.}\right) \frac{(V_t - V_{tb})\ \underline{N} \left(\frac{V_{soln}}{V_a}\right)}{V_{m_{std}}} \qquad \text{equation 6-2}$$

where:

C_{SO_2} = Concentration of sulfur dioxide at standard conditions, dry basis, lb./cu. ft.

$7.05\text{x}10^{-5}$ = Conversion factor, including the number of grams per gram equivalent of sulfur dioxide (32 g./g.-eq.), 453.6 g./lb., and 1,000 ml./l., lb.-l./g.-ml.

V_t = Volume of barium perchlorate titrant used for the sample, ml.

V_{tb} = Volume of barium perchlorate titrant used for the blank, ml.

N = Normality of barium perchlorate titrant, g.-eg./l.

V_{soln} = Total solution volume of sulfur dioxide, 50 ml.

V_a = Volume of sample aliquot titrated, ml.

$V_{m_{std}}$ = Volume of gas sample through the dry gas meter (standard conditions), cu. ft., see Equation 6-1.

7. References

Atmospheric Emissions from Sulfuric Acid Manufacturing Processes, U.S. DHEW, PHS, Division of Air Pollution, Public Health Service Publication No. 999-AP-13, Cincinnati, Ohio, 1965.

Corbett, P. F., The Determination of SO_2 and SO_3 in Flue Gases, Journal of the Institute of Fuel, 24:237-243, 1961.

Matty, R. E. and E. K. Diehl, Measuring Flue-Gas SO_2 and SO_3, Power 101:94-97, November, 1957.

Patton, W. F. and J. A. Brink, Jr., New Equipment and Techniques for Sampling Chemical Process Gases, J. Air Pollution Control Association, 13, 162 (1963).

Method 7 - Determination of Nitrogen Oxide Emissions from Stationary Sources

1. Principle and applicability

1.1 Principle. A grab sample is collected in an evacuated flask containing a dilute sulfuric acid-hydrogen peroxide absorbing solution, and the nitrogen oxides, except nitrous oxide, are measured colorimetrically using the phenoldisulfonic acid (PDS) procedure.

1.2 Applicability. This method is applicable for the measurement of nitrogen oxides from stationary sources only when specified by the test procedures for determining compliance with New Source Performance Standards.

2. Apparatus

2.1 Sampling. See Figure 7-1.

2.1.1 Probe - Pyrex[1] glass, heated, with filter to remove particulate matter. Heating is unnecessary if the probe remains dry during the purging period.

2.1.2 Collection flask - Two-liter, Pyrex[1] round bottom with short neck and 24/40 standard taper opening, protected against implosion or breakage.

2.1.3 Flask valve - T-bore stopcock connected to a 24/40 standard taper joint.

2.1.4 Temperature gauge - Dial-type thermometer, or equivalent, capable of measuring 2°F intervals from 25° to 125°F.

2.1.5 Vacuum line - Tubing capable of withstanding a vacuum of 3 inches Hg absolute pressure, with "T" connection and T-bore stopcock, or equivalent.

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[1] Trade name.

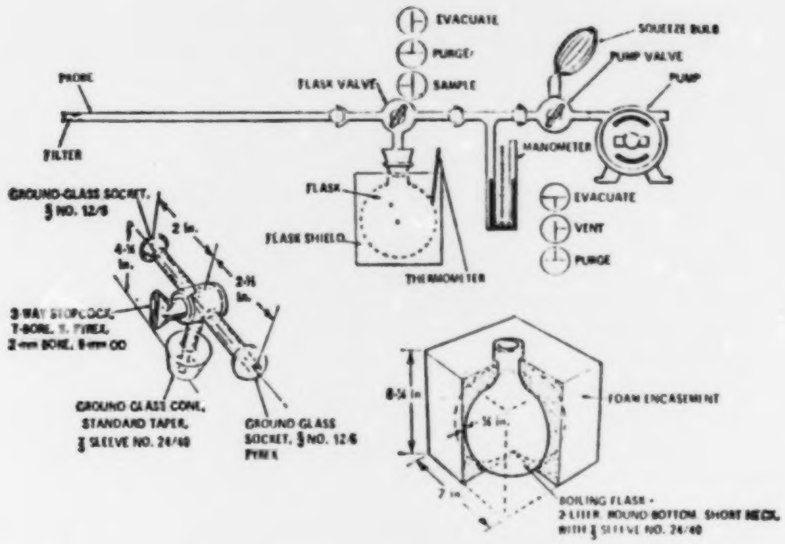

EVACUATE
PURGE/
SAMPLE
SQUEEZE BULB
PUMP VALVE
PROBE
FLASK VALVE
PUMP
FILTER
MANOMETER
FLASK
GROUND-GLASS SOCKET, § NO. 12/5
2 in.
4-½ in.
FLASK SHIELD
EVACUATE
VENT
PURGE
THERMOMETER
2-½ in.
3-WAY STOPCOCK, T-BORE, §, PYREX, 2-mm BORE, 8-mm OD
8-½ in.
FOAM ENCASEMENT
⅜ in.
GROUND GLASS CONE, STANDARD TAPER, § SLEEVE NO. 24/40
GROUND GLASS SOCKET, § NO. 12/5 PYREX
7 in.
BOILING FLASK - 2-LITER, ROUND BOTTOM, SHORT NECK, WITH § SLEEVE NO. 24/40

Figure 7.1. Sampling train, flask valve, and flask.

2.1.6 Pressure gauge - U-tube manometer, 36 inches, with 0.1-inch divisions, or equivalent.

2.1.7 Pump - Capable of producing a vacuum of 3 inches Hg absolute pressure.

2.1.8 Squeeze bulb - One way.

2.2 Sample recovery.

2.2.1 Pipette or dropper.

2.2.2 Glass storage containers - Cushioned for shipping.

2.2.3 Glass wash bottle.

2.3 Analysis.

2.3.1 Steam bath.

2.3.2 Beakers or casseroles - 250 ml., one for each sample and standard (blank).

2.3.3 Volumetric pipettes - 1, 2, and 10 ml.

2.3.4 Transfer pipettes - 10 ml. with 0.1 ml. divisions.

2.3.5 Volumetric flask - 100 ml., one for each sample, and 1,000 ml. for the standard (blank).

2.3.6 Spectrophotometer - To measure absorbance at 420 nm.

2.3.7 Graduated cylinder - 100 ml. with 1.0 ml. divisions.

2.3.8 Analytical balance - To measure to 0.1 mg.

3. Reagents

3.1 Sampling.

3.1.1 Absorbing solution - Add 2.8 ml. of concentrated H_2SO_4 to 1 liter of distilled water. Mix well and add 6 ml. of 3 percent hydrogen peroxide. Prepare a fresh solution weekly and do not expose to extreme heat or direct sunlight.

3.2 Sample recovery.

3.2.1 Sodium hydroxide (1N) - Dissolve 40 g. NaOH in distilled water and dilute to 1 liter.

3.2.2 Red litmus paper.

3.2.3 Water - Deionized, distilled.

3.3 Analysis.

3.3.1 Fuming sulfuric acid - 15 to 18% by weight free sulfur trioxide.

3.3.2 Phenol - White solid reagent grade.

3.3.3 Sulfuric acid - Concentrated reagent grade.

3.3.4 Standard solution - Dissolve 0.5495 g. potassium nitrate (KNO_3) in distilled water and dilute to 1 liter. For the working standard solution, dilute 10 ml. of the resulting solution to 100 ml. with distilled water. One ml. of the working standard solution is equivalent to 25 µg nitrogen dioxide.

3.3.5 Water - Deionized, distilled.

3.3.6 Phenoldisulfonic acid solution - Dissolve 25 g. of pure white phenol in 150 ml. concentrated sulfuric acid on a steam bath. Cool, add 75 ml. fuming sulfuric acid, and heat at 100°C for 2 hours. Store in a dark, stoppered bottle.

4. Procedure.

4.1 Sampling.

4.1.1 Pipette 25 ml. of absorbing solution into a sample flask. Insert the flask valve stopper into the flask with the valve in the "purge" position. Assemble the sampling train as shown in Figure 7-1 and place the probe at the sampling point. Turn the flask valve and the pump valve to their "evacuate" positions. Evacuate the flask to at least 3 inches Hg absolute pressure. Turn the pump valve to its "vent" position and turn off the pump. Check the manometer for any fluctuation in the mercury level. If there is a visible change over the span of one minute, check for leaks. Record the initial volume, temperature, and barometric pressure. Turn the flask valve to its "purge" position, and then do the same with the pump valve. Purge the probe and the vacuum tube using the squeeze bulb. If condensation occurs in the probe and flask valve area, heat the probe and purge until the condensation disappears. Then turn the pump valve to its "vent" position. Turn the flask valve to its "sample" position and allow sample to enter the flask for about 15 seconds. After collecting the sample, turn the flask valve to its "purge" position and disconnect the flask from the sampling train. Shake the flask for 5 minutes.

4.2 Sample recovery.

4.2.1 Let the flask set for a minimum of 16 hours and then shake the contents for 2 minutes. Connect the flask to a mercury filled U-tube manometer, open the valve from the flask to the manometer, and record the flask pressure and temperature along with the barometric pressure. Transfer the flask contents to a container for shipment or to a 250 ml. beaker for analysis. Rinse the flask with two portions of distilled water (approximately 10 ml.) and add rinse water to the sample. For a blank use 25 ml. of absorbing solution and the same volume of distilled water as used in rinsing the flask. Prior to shipping or analysis, add sodium hydroxide (1N) dropwise into both the sample and the blank until alkaline to litmus paper (about 25 to 35 drops in each).

4.3 Analysis.

4.3.1 If the sample has been shipped in a container, transfer the contents to a 250 ml. beaker using a small amount of distilled water. Evaporate the solution to dryness on a steam bath and then cool. Add 2 ml. phenoldisulfonic acid solution to the dried residue and triturate thoroughly with a glass rod, making sure the solution contacts all the residue. Add 1 ml. distilled water and four drops of concentrated sulfuric acid. Heat the solution on a steam bath for 3 minutes with occasional stirring. Cool, add 20 ml. distilled water, mix well by stirring, and add concentrated ammonium hydroxide dropwise with constant stirring until alkaline to litmus paper. Transfer the solution to a 100 ml. volumetric flask and wash the beaker three times with 4 to 5 ml. portions of distilled water. Dilute to the mark and mix thoroughly. If the sample contains solids, transfer a portion of the solution to a clean, dry centrifuge tube, and centrifuge, or filter a portion of the solution. Measure the absorbance of each sample at 420 nm. using the blank solution as a zero. Dilute the sample and the blank with a suitable amount of distilled water if absorbance falls outside the range of calibration.

5. Calibration

5.1 Flask volume. Assemble the flask and flask valve and fill with water to the stop-cock. Measure the volume of water to ±10 ml. Number and record the volume on the flask.

5.2 Spectrophotometer. Add 0.0 to 16.0 ml. of standard solution to a series of beakers. To each beaker add 25 ml. of absorbing solution and add sodium hydroxide (1N) dropwise until alkaline to litmus paper (about 25 to 35 drops). Follow the analysis procedure of section 4.3 to collect enough data to draw a calibration curve of concentration in μg. NO_x per sample versus absorbance.

6. Calculations

6.1 Sample volume.

$$V_{sc} = \frac{T_{std}\,(V_f - V_a)}{P_{std}} \left(\frac{P_f}{T_f} - \frac{P_i}{T_i}\right) = \left(17.71\,\frac{°R}{\text{in. Hg}}\right)(V_f - 25\ \text{ml.}) \left(\frac{P_f}{T_f} - \frac{P_i}{T_i}\right) \qquad \text{equation 7-1}$$

where:

V_{sc} = Sample volume at standard conditions (dry basis), ml.

T_{std} = Absolute temperature at standard conditions, 530°R.

P_{std} = Pressure at standard conditions, 29.92 inches Hg.

V_f = Volume of flask and valve, ml.

V_a = Volume of absorbing solution, 25 ml.

P_f = Final absolute pressure of flask, inches Hg.

P_i = Initial absolute pressure of flask, inches Hg.

T_f = Final absolute temperature of flask, °R.

T_i = Initial absolute temperature of flask, °R.

6.2 Sample concentration. Read μg NO_2 for each sample from the plot of μg. NO_2 versus absorbance.

$$C = \left(\frac{m}{V_{sc}}\right) \left(\frac{\frac{1\ \text{lb.}}{\text{cu. ft.}}}{1.6 \times 10^4\ \frac{\mu\text{g.}}{\text{ml.}}}\right) = \left(6.2 \times 10^{-5}\ \frac{\text{lb./s.c.f.}}{\mu\text{g./ml.}}\right) \left(\frac{m}{V_{sc}}\right) \qquad \text{equation 7-2}$$

where:

C = Concentration of NO_x as NO_2 (dry basis), lb./s.c.f.

m = Mass of NO_2 in gas sample, μg.

V_{sc} = Sample volume at standard conditions (dry basis), ml.

7. References

Standard Methods of Chemical Analysis. 6th ed. New York, D. Van Nostrand Co., Inc., 1962, vol. 1, p. 329-330.

Standard Method of Test for Oxides of Nitrogen in Gaseous Combustion Products (Phenoldisulfonic Acid Procedure), In: 1968 Book of ASTM Designation D-1608-60, p. 725-729.

Jacob, M. B., The Chemical Analysis of Air Pollutants, New York, N. Y., Interscience Publishers, Inc., 1960, vol. 10, p. 351-356.

Method 8 - Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions From Stationary Sources

1. Principle and applicability

1.1 Principle. A gas sample is extracted from a sampling point in the stack and the acid mist including sulfur trioxide is separated from sulfur dioxide. Both fractions are measured separately by the barium-thorin titration method.

1.2 Applicability. This method is applicable to determination of sulfuric acid mist (including sulfur trioxide) and sulfur dioxide from stationary sources only when specified by the test procedures for determining compliance with the New Source Performance Standards.

2. Apparatus

2.1 Sampling. See Figure 8-1. Many of the design specifications of this sampling train are described in APTD-0581.

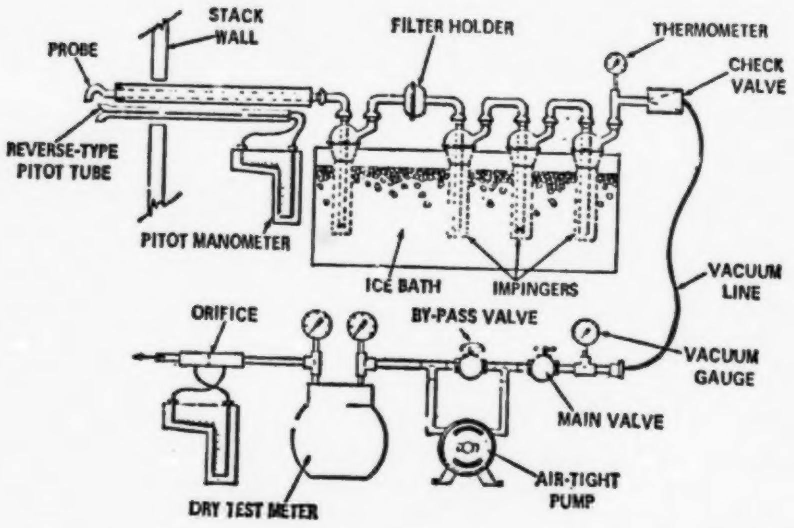

STACK WALL
FILTER HOLDER
THERMOMETER
PROBE
CHECK VALVE
REVERSE-TYPE PITOT TUBE
PITOT MANOMETER
ICE BATH
IMPINGERS
VACUUM LINE
ORIFICE
BY-PASS VALVE
VACUUM GAUGE
MAIN VALVE
AIR-TIGHT PUMP
DRY TEST METER

Figure 8.1. Sulfuric acid mist sampling train.

2.1.1 Nozzle - Stainless steel (316) with sharp, tapered leading edge.

2.1.2 Probe - Pyrex[1] glass with a heating system to prevent visible condensation during sampling.

2.1.3 Pitot tube - Type S, or eqivalent, attached to probe to monitor stack gas velocity.

2.1.4 Filter holder - Pyrexl glass.

2.1.5 Impingers - Four as shown in Figure 8-1. The first and third are of the Greenburg-Smith design with standard tip. The second and fourth are of the Greenburg-Smith design, modified by replacing the standard tip with a 1/2-inch ID glass tube extending to one-half inch from the bottom of the impinger flask. Similar collection systems, which have been approved by the Administrator, may be used.

2.1.6 Metering system - Vacuum gauge, leak-free pump, thermometers capable of measuring temperature to within 5°F., dry gas meter with 2% accuracy, and related equipment, or equivalent, as required to maintain an isokinetic sampling rate and to determine sample volume.

2.1.7 Barometer - To measure atmospheric pressure to ±0.1 inch Hg.

2.2 Sample recovery.

2.2.1 Wash bottles - Two.

2.2.2 Graduated cylinders - 250 ml., 500 ml.

2.2.3 Glass sample storage containers.

2.2.4 Graduated cylinder - 250 ml.

2.3 Analysis

2.3.1 Pipette - 25 ml., 100 ml.

2.3.2 Burette - 50 ml.

2.3.3 Erlenmeyer flask - 250 ml.

2.3.4 Graduated cylinder - 100 ml.

2.3.5 Trip balance - 300 g. capacity, to measure to ±0.05 g.

2.3.6 Dropping bottle - To add indicator solution.

3. Reagents

3.1 Sampling.

3.1.1 Filters - Glass fiber, MSA type 1106 BH, or equivalent, of a suitable size to fit in the filter holder.

3.1.2 Silica gel - Indicating type, 6-16 mesh, dried at 175°C (350°F) for 2 hours.

3.1.3 Water - Deionized, distilled.

3.1.4 Isopropanol, 80% - Mix 800 ml. of isopropanol with 200 ml. of deionized, distilled water.

3.1.5 Hydrogen peroxide, 3% - Dilute 100 ml of 30% hydrogen peroxide to 1 liter with deionized, distilled water.

3.1.6 Crushed ice.

3.2 Sample recovery.

3.2.1 Water - Deionized, distilled.

3.2.2 Isopropanol, 80%.

---

[1] Trade name.

3.3 Analysis.

3.3.1 Water - Deionized, distilled.

3.3.2 Isopropanol.

3.3.3 Thorin indicator - 1-(o-arsonophenylazo)-2-naphthol-3, 6-disulfonic acid, disodium salt (or equivalent). Dissolve 0.20 g. in 100 ml. distilled water.

3.3.4 Barium perchlorate (0.01N) - Dissolve 1.95 g. of barium perchlorate [$Ba(CO_4)_2 \cdot 3H_2O$] in 200 ml. distilled water and dilute 1 liter with isopropanol. Standardize with sulfuric acid.

3.3.5 Sulfuric acid standard (0.01N) - Purchase or standardize to ±0.0002N against 0.01 N NaOH which has previously been standardized against primary standard potassium acid phthalate.

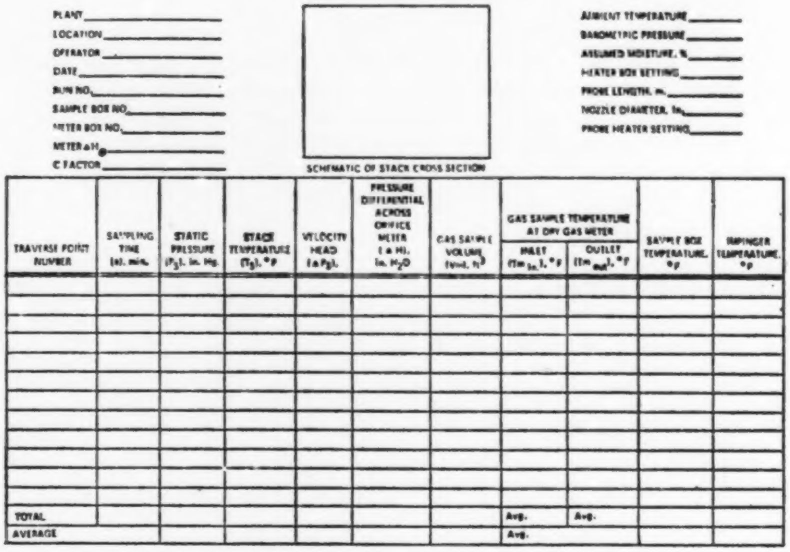
4. Procedure

4.1 Sampling.

4.1.1 After selecting the sampling site and the minimum number of sampling points, determine the stack pressure, temperature, moisture, and range of velocity head.

4.1.2 Preparation of collection train. Place 100 ml. of 80% isopropanol in the first impinger, 100 ml. of 3% hydrogen peroxide in both the second and third impingers, and about 200 g. of silica gel in the fourth impinger. Retain a portion of the reagents for use as blank solutions. Assemble the train without the probe as shown in Figure 8-1 with the filter between the first and second impingers. Leak check the sampling train at the sampling site by plugging the inlet to the first impinger and pulling a 15-inch Hg vacuum. A leakage rate not in excess of 0.02 c.f.m. at a vacuum of 15 inches Hg is acceptable. Attach the probe and turn on the probe heating system. Adjust the probe heater setting during sampling to prevent any visible condensation. Place crushed ice around the impingers. Add more ice during the run to keep the temperature of the gases leaving the last impinger at 70°F or less.

4.1.3 Train operation. For each run, record the data required on the example sheet shown in Figure 8-2. Take readings at each sampling point at least every 5 minutes and when significant changes in stack conditions necessitate additional adjustments in flow rate. To begin sampling, position the nozzle at the first traverse point with the tip pointing directly into the gas stream. Start the pump and immediately adjust the flow to isokinetic conditions. Maintain isokinetic sampling throughout the sampling period. Nomographs are available which aid in the rapid adjustment of the sampling rate without other computations. APTD-0576 details the procedure for using these nomographs. At the conclusion of each run, turn off the pump and record the final readings. Remove the probe from the stack and disconnect it from the train. Drain the ice bath and purge the remaining part of the train by drawing clean ambient air through the system for 15 minutes.



PLANT ______
LOCATION ______
OPERATOR ______
DATE ______
RUN NO. ______
SAMPLE BOX NO. ______
METER BOX NO. ______
METER $\Delta H_@$ ______
C FACTOR ______

SCHEMATIC OF STACK CROSS SECTION

AMBIENT TEMPERATURE ______
BAROMETRIC PRESSURE ______
ASSUMED MOISTURE, % ______
HEATER BOX SETTING ______
PROBE LENGTH, m. ______
NOZZLE DIAMETER, in. ______
PROBE HEATER SETTING ______

TRAVERSE POINT NUMBER	SAMPLING TIME (θ), min.	STATIC PRESSURE (P_s), in. Hg.	STACK TEMPERATURE (T_s), °F	VELOCITY HEAD (ΔP_s)	PRESSURE DIFFERENTIAL ACROSS ORIFICE METER (ΔH), in. H_2O	GAS SAMPLE VOLUME (V_m), ft³	GAS SAMPLE TEMPERATURE AT DRY GAS METER		SAMPLE BOX TEMPERATURE, °F	IMPINGER TEMPERATURE, °F
							INLET ($T_{m_{in}}$), °F	OUTLET ($T_{m_{out}}$), °F		
TOTAL							Avg.	Avg.		
AVERAGE							Avg.			

Figure 8.2. Field data.

4.2 Sample recovery.

4.2.1 Transfer the isopropanol from the first impinger to a 250 ml. graduated cylinder. Rinse the probe, first impinger, and all connecting glassware before the filter with 80% isopropanol. Add the rinse solution to the cylinder. Dilute to 250 ml. with 80% isopropanol. Add the filter to the solution, mix, and transfer to a suitable storage container. Transfer the solution from the second and third impingers to a 500 ml. graduated cylinder. Rinse all glassware between the filter and silica gel impinger with deionized, distilled water and add this rinse water to the cylinder. Dilute to a volume of 500 ml. with deionized, distilled water. Transfer the solution to a suitable storage container.

4.3 Analysis.

4.3.1 Shake the container holding isopropanol and the filter. If the filter breaks up, allow the fragments to settle for a few minutes before removing a sample. Pipette a 100 ml. aliquot of sample into a 250 ml. Erlenmeyer flask and add 2 to 4 drops of thorin indicator. Titrate the sample with barium perchlorate to a pink end point. Make sure to record volumes. Repeat the titration with a second aliquot of sample. Shake the container holding the contents of the second and third impingers. Pipette a 25 ml. aliquot of sample into a 250 ml. Erlenmeyer flask. Add 100 ml. of isopropanol and 2 to 4 drops of thorin indicator. Titrate the sample with barium perchlorate to a pink end point. Repeat the titration with a second aliquot of sample. Titrate the blanks in the same manner as the samples.

5. Calibration

5.1 Use standard methods and equipment which have been approved by the Administrator to calibrate the orifice meter, pitot tube, dry gas meter, and probe heater.
5.2 Standardize the barium perchlorate with 25 ml. of standard sulfuric acid containing 100 ml. of isopropanol.

6. Calculations

6.1 Dry gas volume. Correct the sample volume measured by the dry gas meter to standard conditions (70°F, 29.92 inches Hg) by using Equation 8-1.

$$V_{m_{std}} = V_m \left(\frac{T_{std}}{T_m}\right) \left(\frac{P_{bar} + \frac{\Delta H}{13.6}}{P_{std}}\right) = \left(17.71 \frac{°R}{\text{in. Hg}}\right) V_m \left(\frac{P_{bar} + \frac{\Delta H}{13.6}}{T_m}\right) \qquad \text{equation 8-1}$$

where:

$V_{m_{std}}$ = Volume of gas sample through the dry gas meter (standard conditions), cu. ft.

V_m = Volume of gas sample through the dry gas meter (meter conditions), cu. ft.

T_{std} = Absolute temperature at standard conditions, 530°R.

T_m = Average dry gas meter temperature, °R.

P_{bar} = Barometric pressure at the orifice meter, inches Hg.

ΔH = Pressure drop across the orifice meter, inches H_2O.

13.6 = Specific gravity of mercury.

P_{std} = Absolute pressure at standard conditions, 29.92 inches Hg.

6.2 Sulfuric acid concentration.

$$C_{H_2SO_4} = \left(1.08 \times 10^{-4}\ \frac{\text{lb.-l.}}{\text{g.-ml.}}\right) \frac{(V_t - V_{tb})(\underline{N})\left(\frac{V_{soln}}{V_a}\right)}{V_{m_{std}}} \qquad \text{equation 8-2}$$

where:

$C_{H_2SO_4}$ = Concentration of sulfuric acid at standard conditions, dry basis, lb./cu.ft.

1.08×10^{-4} = Conversion factor including the number of grams per gram equivalent of sulfuric acid (49 g./g.-eq.), 453.6 g./lb., and 1,000 ml./l., lb.-l./g.-ml.

V_t = Volume of barium perchlorate titrant used for the sample, ml.

V_{tb} = Volume of barium perchlorate titrant used for the blank, ml.

N = Normality of barium perchlorate titrant, g.-eq./l.

V_{soln} = Total solution volume of sulfuric acid (first impinger and filter), ml.

V_a = Volume of sample aliquot titrated, ml.

Vm_{std} = Volume of gas sample through the dry gas meter (standard conditions), cu. ft., see Equation 8-1.

6.3 Sulfur dioxide concentration.

$$C_{SO_2} = \left(7.05 \times 10^{-5}\ \frac{\text{lb.-l.}}{\text{g.-ml.}}\right) \frac{(V_t - V_{tb})(\underline{N})\left(\frac{V_{soln}}{V_a}\right)}{V_{m_{std}}} \qquad \text{equation 8-3}$$

where:

C_{SO_2} = Concentration of sulfur dioxide at standard conditions, dry basis, lb./cu.ft.

7.05×10^{-5} = Conversion factor including the number of grams per gram equivalent of sulfur dioxide (32 g./g.-eq.) 453.6 g./lb., and 1,000 ml./l., lb.-l./g.-ml.

V_t = Volume of barium perchlorate titrant used for the sample, ml.

V_{tb} = Volume of barium perchlorate titrant used for the blank, ml.

N = Normality of barium perchlorate titrant, g.-eq./l.

V_{soln} = Total solution volume of sulfur dioxide (second and third impingers), ml.

V_a = Volume of sample aliquot titrated, ml.

$V_{m_{std}}$ = Volume of gas sample through the dry gas meter (standard conditions), cu. ft., see Equation 8-1.

7. References

Atmospheric Emissions from Sulfuric Acid Manufacturing Processes, U.S. DHEW, PHS, Division of Air Pollution, Public Health Service Publication No. 999-AP-13, Cincinnati, Ohio, 1965.

Corbett, D. F., The Determination of SO_2 and SO_3 in Flue Gases, Journal of the Institute of Fuel, 24:237-243, 1961.

Martin, Robert M., Construction Details of Isokinetic Source Sampling Equipment, Environmental Protection Agency, Air Pollution Control Office Publication No. APTD-0581.

Patton, W. F., and J. A. Brink, Jr., New Equipment and Techniques for Sampling Chemical Process Gases, J. Air Pollution Control Assoc. 13, 162 (1963).

Rom, Jerome J., Maintenance, Calibration, and Operation of Isokinetic Source Sampling Equipment, Environmental Protection Agency, Air Pollution Control Office Publication No. APTD-0576.

Shell Development Co. Analytical Department, Determination of Sulfur Dioxide and Sulfur Trioxide in Stack Gases, Emeryville Method Series, 4516/59a.

Method 9 - Visual Determination of Opacity of Emissions From Stationary Sources

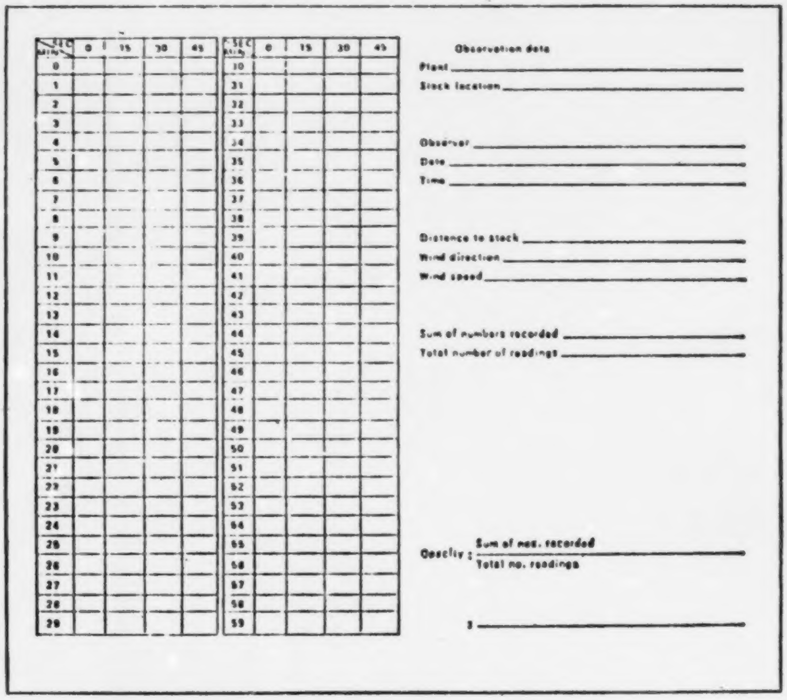
1. Principle and applicability

1.1 Principle. The relative opacity of an emission from a stationary source is determined visually by a qualified observer.

1.2 Applicability. This method is applicable for the determination of the relative opacity of visible emissions from stationary sources only when specified by test procedures for determining compliance with the New Source Performance Standards.

2. Procedure

2.1 The qualified observer stands at approximately two stack heights, but not more than a quarter of a mile from the base of the stack with the sun to his back. From a vantage point perpendicular to the plume, the observer studies the point of greatest opacity in the plume. The data required in Figure 9-1 is recorded every 15 to 30 seconds to the nearest 5 percent opacity. A minimum of 25 readings is taken.



SEC / MIN	0	15	30	45	SEC / MIN	0	15	30	45
0					30				
1					31				
2					32				
3					33				
4					34				
5					35				
6					36				
7					37				
8					38				
9					39				
10					40				
11					41				
12					42				
13					43				
14					44				
15					45				
16					46				
17					47				
18					48				
19					49				
20					50				
21					51				
22					52				
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24					54				
25					55				
26					56				
27					57				
28					58				
29					59				

Observation data

Plant __________
Stack location __________

Observer __________
Date __________
Time __________

Distance to stack __________
Wind direction __________
Wind speed __________

Sum of numbers recorded __________
Total number of readings __________

Opacity = $\frac{\text{Sum of nos. recorded}}{\text{Total no. readings}}$

% __________

Figure 9.1. Field data.

3. Qualifications

3.1 To certify as an observer, a candidate must complete a smokereading course conducted by EPA, or equivalent; in order to certify the candidate must assign opacity readings in 5% increments to 25 different black plumes and 25 different white plumes, with an error not to exceed 15 percent on any one reading and an average error not to exceed 7.5 percent in each category. The smoke generator used to qualify the observers must be equipped with a calibrated smoke indicator or light transmission meter located in the source stack if the smoke generator is to determine the actual opacity of the emissions. All qualified observers must pass this test every 6 months in order to remain certified.

4. Calculations

4.1 Determine the average opacity.

5. References

Air Pollution Control District Rules and Regulations, Los Angeles County Air Pollution Control District, Chapter 2, Schedule 6, Regulation 4, Prohibition, Rule 50, 17 p.

Kudluk, Rudolf, Ringelmann Smoke Chart, U.S. Department of Interior, Bureau of Mines, Information Circular No. 8333, May 1967.

APPENDIX B

VISIBLE EMISSION OBSERVATION FORM

RECORD OF VISUAL DETERMINATION OF OPACITY

PAGE___ of___

COMPANY____________________
LOCATION____________________
TEST NUMBER____________________
DATE____________________
TYPE FACILITY____________________
CONTROL DEVICE____________________

HOURS OF OBSERVATION____________________
OBSERVER____________________
OBSERVER CERTIFICATION DATE____________________
OBSERVER AFFILIATION____________________
POINT OF EMISSIONS____________________
HEIGHT OF DISCHARGE POINT____________________

	Initial			Final
CLOCK TIME				
OBSERVER LOCATION Distance to Discharge				
Direction from Discharge				
Height of Observation Point				
BACKGROUND DESCRIPTION				
WEATHER CONDITIONS Wind Direction				
Wind Speed				
Ambient Temperature				
SKY CONDITIONS (clear, overcast, % clouds, etc.)				
PLUME DESCRIPTION Color				
Distance Visible				
OTHER INFORMATION				

SUMMARY OF AVERAGE OPACITY

Set Number	Time	Opacity	
	Start--End	Sum	Average

Readings ranged from ____ to ____ % opacity

The source was/was not in compliance with ____ at the time evaluation was made.

OBSERVATION RECORD PAGE ___ OF ___

COMPANY ____________
LOCATION ____________
TEST NUMBER ____________
DATE ____________

OBSERVER ____________
TYPE FACILITY ____________
POINT OF EMISSIONS ____________

Hr.	Min.	Seconds				STEAM PLUME (check if applicable)		COMMENTS
		0	15	30	45	Attached	Detached	
	0							
	1							
	2							
	3							
	4							
	5							
	6							
	7							
	8							
	9							
	10							
	11							
	12							
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	15							
	16							
	17							
	18							
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	20							
	21							
	22							
	23							
	24							
	25							
	26							
	27							
	28							
	29							

OBSERVATION RECORD PAGE ___ OF ___

COMPANY ____________
LOCATION ____________
TEST NUMBER ____________
DATE ____________

OBSERVER ____________
TYPE FACILITY ____________
POINT OF EMISSIONS ____________

Hr.	Min.	Seconds				STEAM PLUME (check if applicable)		COMMENTS
		0	15	30	45	Attached	Detached	
	30							
	31							
	32							
	33							
	34							
	35							
	36							
	37							
	38							
	39							
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	59							

[FR Doc.74-26150 Filed 11-11-74;8:45 am]

APPENDIX C

SUGGESTED CONTENTS OF STACK TEST REPORTS

CONTENTS OF STACK TEST REPORTS

In order to adequately assess the accuracy of any test report the basic information listed in the following suggested outline is necessary:

1. Introduction. Background information pertinent to the test is presented in this section. This information shall include, but not be limited to, the following:
   - a. Manufacturer's name and address.
   - b. Name and address of testing organization.
   - c. Names of persons present, dates and location of test.
   - d. Schematic drawings of the process being tested showing emission points, sampling sites, and stack cross section with the sampling points labeled and dimensions indicated.
2. Summary. This section shall present a summary of test findings pertinent to the evaluation of the process with respect to the applicable emission standard. The information shall include, but not be limited to, the following:
   - a. A summary of emission rates found.
   - b. Isokinetic sampling rates achieved if applicable.
   - c. The operating level of the process while the tests were conducted.
3. Procedure. This section shall describe the procedures used and the operation of the sampling train and process during the tests. The information shall include, but not be limited to, the following:
   - a. A schematic drawing of the sampling devices used with each component designated and explained in a legend.
   - b. A brief description of the method used to operate the sampling train and procedure used to recover samples.

4. Analytical Technique. This section shall contain a brief description of all analytical techniques used to determine the emissions from the source.

5. Data and Calculations. This section shall include all data collected and calculations. As a minimum, this section shall contain the following information:

   a. All field data collected on raw data sheets.

   b. A log of process and sampling train operations.

   c. Laboratory data including blanks, tare weights and results of analysis.

   d. All emission calculations.

6. Chain of Custody. A listing of the chain of custody of the emission test samples.

7. Appendix:

   a. Calibration work sheets for sampling equipment.

   b. Calibration or process logs of process parameters.

APPENDIX D

GAS CONVERSION GRAPHS

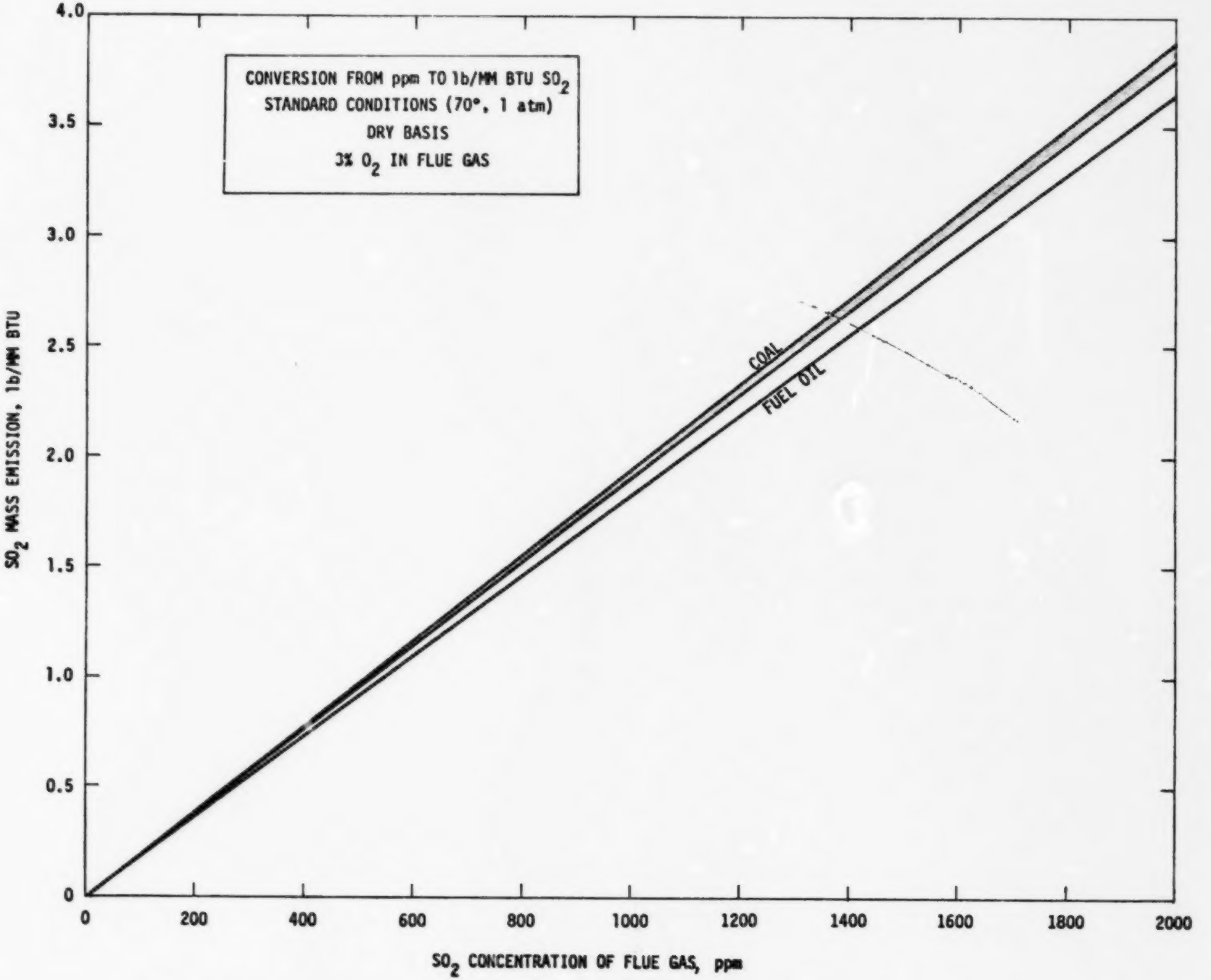

Figure D1. SO_2 conversion graph: ppm to lb/MM BTU heat input.

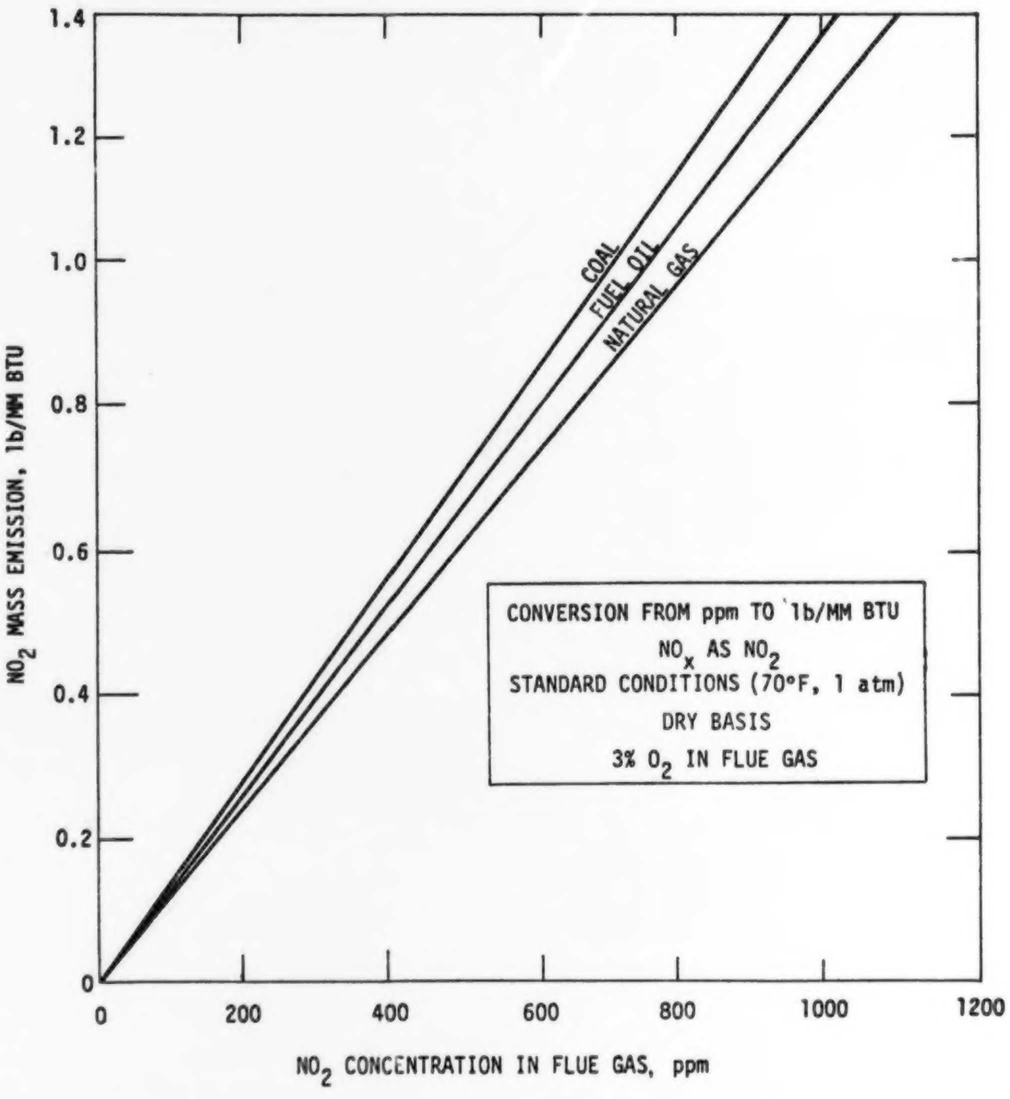

Figure D2. NO_x conversion graph: ppm to lb/MM BTU heat input.